

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 December 31, 2024

or

☐ **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	Exact name of registrant as specified in its charter; State or other jurisdiction of incorporation or organization	IRS Employer Identification No.
001-14881	BERKSHIRE HATHAWAY ENERGY COMPANY (An Iowa Corporation) 1615 Locust Street Des Moines, Iowa 50309-3037 515-242-4300	94-2213782
001-05152	PACIFICORP (An Oregon Corporation) 825 N.E. Multnomah Street Portland, Oregon 97232 888-221-7070	93-0246090
333-90553	MIDAMERICAN FUNDING, LLC (An Iowa Limited Liability Company) 1615 Locust Street Des Moines, Iowa 50309-3037 515-242-4300	47-0819200
333-15387	MIDAMERICAN ENERGY COMPANY (An Iowa Corporation) 1615 Locust Street Des Moines, Iowa 50309-3037 515-242-4300	42-1425214
000-52378	NEVADA POWER COMPANY (A Nevada Corporation) 6226 West Sahara Avenue Las Vegas, Nevada 89146 702-402-5000	88-0420104
000-00508	SIERRA PACIFIC POWER COMPANY (A Nevada Corporation) 6100 Neil Road Reno, Nevada 89511 775-834-4011	88-0044418
001-37591	EASTERN ENERGY GAS HOLDINGS, LLC (A Virginia Limited Liability Company) 10700 Energy Way Glen Allen, Virginia 23060 804-613-5100	46-3639580
333-266049	EASTERN GAS TRANSMISSION AND STORAGE, INC. (A Delaware Corporation) 10700 Energy Way Glen Allen, Virginia 23060 804-613-5100	55-0629203

Registrant	Securities registered pursuant to Section 12(b) of the Act:
BERKSHIRE HATHAWAY ENERGY COMPANY	None
PACIFICORP	None
MIDAMERICAN FUNDING, LLC	None
MIDAMERICAN ENERGY COMPANY	None
NEVADA POWER COMPANY	None
SIERRA PACIFIC POWER COMPANY	None
EASTERN ENERGY GAS HOLDINGS, LLC	None
EASTERN GAS TRANSMISSION AND STORAGE, INC.	None

Registrant	Name of exchange on which registered:
BERKSHIRE HATHAWAY ENERGY COMPANY	None
PACIFICORP	None
MIDAMERICAN FUNDING, LLC	None
MIDAMERICAN ENERGY COMPANY	None
NEVADA POWER COMPANY	None
SIERRA PACIFIC POWER COMPANY	None
EASTERN ENERGY GAS HOLDINGS, LLC	None
EASTERN GAS TRANSMISSION AND STORAGE, INC.	None

Registrant	Securities registered pursuant to Section 12(g) of the Act:
BERKSHIRE HATHAWAY ENERGY COMPANY	None
PACIFICORP	None
MIDAMERICAN FUNDING, LLC	None
MIDAMERICAN ENERGY COMPANY	None
NEVADA POWER COMPANY	Common Stock, \$1.00 stated value
SIERRA PACIFIC POWER COMPANY	Common Stock, \$3.75 par value
EASTERN ENERGY GAS HOLDINGS, LLC	None
EASTERN GAS TRANSMISSION AND STORAGE, INC.	None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Registrant	Yes	No
BERKSHIRE HATHAWAY ENERGY COMPANY	☐	☒
PACIFICORP	☒	☐
MIDAMERICAN FUNDING, LLC	☐	☒
MIDAMERICAN ENERGY COMPANY	☒	☐
NEVADA POWER COMPANY	☒	☐
SIERRA PACIFIC POWER COMPANY	☐	☒
EASTERN ENERGY GAS HOLDINGS, LLC	☒	☐
EASTERN GAS TRANSMISSION AND STORAGE, INC.	☐	☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Registrant	Yes	No
BERKSHIRE HATHAWAY ENERGY COMPANY	☐	☒
PACIFICORP	☐	☒
MIDAMERICAN FUNDING, LLC	☒	☐
MIDAMERICAN ENERGY COMPANY	☐	☒
NEVADA POWER COMPANY	☐	☒
SIERRA PACIFIC POWER COMPANY	☐	☒
EASTERN ENERGY GAS HOLDINGS, LLC	☐	☒
EASTERN GAS TRANSMISSION AND STORAGE, INC.	☐	☒

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.

Registrant	Yes	No
BERKSHIRE HATHAWAY ENERGY COMPANY	☒	☐
PACIFICORP	☒	☐
MIDAMERICAN FUNDING, LLC	☐	☒
MIDAMERICAN ENERGY COMPANY	☒	☐
NEVADA POWER COMPANY	☒	☐
SIERRA PACIFIC POWER COMPANY	☒	☐
EASTERN ENERGY GAS HOLDINGS, LLC	☒	☐
EASTERN GAS TRANSMISSION AND STORAGE, INC.	☒	☐

Indicate by check mark whether the registrants have 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 registrants were 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.

Registrant	Large accelerated filer	Accelerated filer	Non-accelerated filer	Smaller reporting company	Emerging growth company
BERKSHIRE HATHAWAY ENERGY COMPANY	☐	☐	☒	☐	☐
PACIFICORP	☐	☐	☒	☐	☐
MIDAMERICAN FUNDING, LLC	☐	☐	☒	☐	☐
MIDAMERICAN ENERGY COMPANY	☐	☐	☒	☐	☐
NEVADA POWER COMPANY	☐	☐	☒	☐	☐
SIERRA PACIFIC POWER COMPANY	☐	☐	☒	☐	☐
EASTERN ENERGY GAS HOLDINGS, LLC	☐	☐	☒	☐	☐
EASTERN GAS TRANSMISSION AND STORAGE, INC.	☐	☐	☒	☐	☐

If an emerging growth company, indicate by check mark if the registrants have 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 registrants are a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

All shares of outstanding common stock of Berkshire Hathaway Energy Company are held by its parent company, Berkshire Hathaway Inc. As of January 31, 2025, 1 share of common stock, no par value, was outstanding.

All shares of outstanding common stock of PacifiCorp are indirectly held by Berkshire Hathaway Energy Company. As of January 31, 2025, 357,060,915 shares of common stock, no par value, were outstanding.

All of the member's equity of MidAmerican Funding, LLC is held by its parent company, Berkshire Hathaway Energy Company, as of January 31, 2025.

All shares of outstanding common stock of MidAmerican Energy Company are held by its parent company, MHC Inc., which is a direct, wholly owned subsidiary of MidAmerican Funding, LLC. As of January 31, 2025, 70,980,203 shares of common stock, no par value, were outstanding.

All shares of outstanding common stock of Nevada Power Company are held by its parent company, NV Energy, Inc., which is an indirect, wholly owned subsidiary of Berkshire Hathaway Energy Company. As of January 31, 2025, 1,000 shares of common stock, \$1.00 stated value, were outstanding.

All shares of outstanding common stock of Sierra Pacific Power Company are held by its parent company, NV Energy, Inc. As of January 31, 2025, 1,000 shares of common stock, \$3.75 par value, were outstanding.

All of the member's equity of Eastern Energy Gas Holdings, LLC is held indirectly by its parent company, Berkshire Hathaway Energy Company, as of January 31, 2025.

All shares of outstanding common stock of Eastern Gas Transmission and Storage, Inc. are held by its parent company, Eastern Energy Gas Holdings, LLC, which is an indirect, wholly owned subsidiary of Berkshire Hathaway Energy Company. As of January 31, 2025, 60,101 shares of common stock, \$10,000 par value, were outstanding.

Berkshire Hathaway Energy Company, PacifiCorp, MidAmerican Funding, LLC, MidAmerican Energy Company, Nevada Power Company, Sierra Pacific Power Company, Eastern Energy Gas Holdings, LLC and Eastern Gas Transmission and Storage, Inc. meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and are therefore filing portions of this Form 10-K with the reduced disclosure format specified in General Instruction I(2) of Form 10-K.

This combined Form 10-K is separately filed by Berkshire Hathaway Energy Company, PacifiCorp, MidAmerican Funding, LLC, MidAmerican Energy Company, Nevada Power Company, Sierra Pacific Power Company, Eastern Energy Gas Holdings, LLC and Eastern Gas Transmission and Storage, Inc. Information contained herein relating to any individual company is filed by such company on its own behalf. Each company makes no representation as to information relating to the other companies.

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Definition of Abbreviations and Industry Terms

When used in Forward-Looking Statements, Part I - Items 1 through 4, Part II - Items 5 through 7A, and Part III - Items 10 through 14, the following terms have the definitions indicated.

Entity Definitions

BHE	Berkshire Hathaway Energy Company
Berkshire Hathaway	Berkshire Hathaway Inc.
Berkshire Hathaway Energy or the Company	Berkshire Hathaway Energy Company and its subsidiaries
PacifiCorp	PacifiCorp and its subsidiaries
MidAmerican Funding	MidAmerican Funding, LLC and its subsidiaries
MidAmerican Energy	MidAmerican Energy Company
NV Energy	NV Energy, Inc. and its subsidiaries
Nevada Power	Nevada Power Company and its subsidiaries
Sierra Pacific	Sierra Pacific Power Company and its subsidiaries
Nevada Utilities	Nevada Power Company and its subsidiaries and Sierra Pacific Power Company and its subsidiaries
EEGH	Eastern Energy Gas Holdings, LLC
Eastern Energy Gas	Eastern Energy Gas Holdings, LLC and its subsidiaries
EGTS	Eastern Gas Transmission and Storage, Inc. and its subsidiaries
Registrants	Berkshire Hathaway Energy Company, PacifiCorp and its subsidiaries, MidAmerican Funding, LLC and its subsidiaries, MidAmerican Energy Company, Nevada Power Company and its subsidiaries, Sierra Pacific Power Company and its subsidiaries, Eastern Energy Gas Holdings, LLC and its subsidiaries and Eastern Gas Transmission and Storage, Inc. and its subsidiaries
Subsidiary Registrants	PacifiCorp and its subsidiaries, MidAmerican Funding, LLC and its subsidiaries, MidAmerican Energy Company, Nevada Power Company and its subsidiaries, Sierra Pacific Power Company and its subsidiaries, Eastern Energy Gas Holdings, LLC and its subsidiaries and Eastern Gas Transmission and Storage, Inc. and its subsidiaries
Northern Powergrid	Northern Powergrid Holdings Company and its subsidiaries
BHE GT&S	BHE GT&S, LLC and its subsidiaries
Northern Natural Gas	Northern Natural Gas Company
Kern River	Kern River Gas Transmission Company
CGT	Carolina Gas Transmission, LLC
BHE Canada	BHE Canada Holdings Corporation and its subsidiaries
AltaLink	AltaLink, L.P.
BHE U.S. Transmission	BHE U.S. Transmission, LLC and its subsidiaries
HomeServices	HomeServices of America, Inc. and its subsidiaries
BHE Pipeline Group or Pipeline Companies	BHE GT&S, LLC, Northern Natural Gas Company and Kern River Gas Transmission Company
BHE Transmission	BHE Canada Holdings Corporation and BHE U.S. Transmission, LLC
BHE Renewables	BHE Renewables, LLC and its subsidiaries
ETT	Electric Transmission Texas, LLC
Domestic Regulated Businesses	PacifiCorp and its subsidiaries, MidAmerican Energy Company, Nevada Power Company and its subsidiaries, Sierra Pacific Power Company and its subsidiaries, BHE GT&S, LLC and its subsidiaries, Northern Natural Gas Company and Kern River Gas Transmission Company
Regulated Businesses	PacifiCorp and its subsidiaries, MidAmerican Energy Company, Nevada Power Company and its subsidiaries, Sierra Pacific Power Company and its subsidiaries, BHE GT&S, LLC and its subsidiaries, Northern Natural Gas Company, Kern River Gas Transmission Company and AltaLink, L.P.

Utilities	PacifiCorp and its subsidiaries, MidAmerican Energy Company, Nevada Power Company and its subsidiaries and Sierra Pacific Power Company and its subsidiaries
Northern Powergrid Distribution Companies	Northern Powergrid (Northeast) plc and Northern Powergrid (Yorkshire) plc
Topaz	Topaz Solar Farms LLC
Topaz Project	550-megawatt solar project in California
Agua Caliente	Agua Caliente Solar, LLC
Agua Caliente Project	290-megawatt solar project in Arizona
Bishop Hill II	Bishop Hill Energy II LLC
Bishop Hill Project	81-megawatt wind-powered generating facility in Illinois
Pinyon Pines I	Pinyon Pines Wind I, LLC
Pinyon Pines II	Pinyon Pines Wind II, LLC
Pinyon Pines Projects	168-megawatt and 132-megawatt wind-powered generating facilities in California
Jumbo Road	Jumbo Road Holdings, LLC
Jumbo Road Project	300-megawatt wind-powered generating facility in Texas
Solar Star Funding	Solar Star Funding, LLC
Solar Star Projects	A combined 586-megawatt solar project in California
Solar Star I	Solar Star California XIX, LLC
Solar Star II	Solar Star California XX, LLC
Cove Point	Cove Point LNG, LP
Iroquois	Iroquois Gas Transmission System, L.P.
DEI	Dominion Energy, Inc.
Liquefaction Facility	A natural gas export/liquefaction facility

Certain Industry Terms

2020 Wildfires	Wildfires in Oregon and Northern California that occurred in September 2020
2022 McKinney Fire	A wildfire that began in the Oak Knoll Ranger District of the Klamath National Forest in Siskiyou County, California in July 2022
Wildfires	2020 Wildfires and 2022 McKinney Fire
AESO	Alberta Electric System Operator
AFUDC	Allowance for Funds Used During Construction
AOCI	Accumulated Other Comprehensive Income (Loss)
ARO	Asset Retirement Obligation
ASC	Accounting Standards Codification
AUC	Alberta Utilities Commission
BART	Best Available Retrofit Technology
Bcf	Billion cubic feet
BTER	Base Tariff Energy Rate
California ISO	California Independent System Operator Corporation
CCR	Coal Combustion Residuals
CPUC	California Public Utilities Commission
CSAPR	Cross-State Air Pollution Rule
D.C. Circuit	U.S. Court of Appeals for the District of Columbia Circuit
DEAA	Deferred Energy Accounting Adjustment
DOE	U.S. Department of Energy
Dodd-Frank Reform Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
DOT	U.S. Department of Transportation
Dth	Decatherm

DSM	Demand Side Management
EAC	Energy Adjustment Clause
EBA	Energy Balancing Account
ECAC	Energy Cost Adjustment Clause
ECAM	Energy Cost Adjustment Mechanism
EEIR	Energy Efficiency Implementation Rate
EEPR	Energy Efficiency Program Rate
EIM	Energy Imbalance Market
EPA	U.S. Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FIP	Federal Implementation Plan
GAAP	Accounting principles generally accepted in the United States of America
GEMA	Gas and Electricity Markets Authority
GHG	Greenhouse Gases
GWh	Gigawatt Hour
ICC	Illinois Commerce Commission
IPUC	Idaho Public Utilities Commission
IRP	Integrated Resource Plan
IUC	Iowa Utilities Commission
kV	Kilovolt
LNG	Liquefied Natural Gas
LDC	Local Distribution Company
MATS	Mercury and Air Toxics Standards
MISO	Midcontinent Independent System Operator, Inc.
MW	Megawatt
MWh	Megawatt Hour
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NO _x	Nitrogen Oxides
NRC	Nuclear Regulatory Commission
OATT	Open Access Transmission Tariff
OCI	Other Comprehensive Income (Loss)
Ofgem	Office of Gas and Electric Markets
OPUC	Oregon Public Utility Commission
PCAM	Power Cost Adjustment Mechanism
PGA	Purchased Gas Adjustment Clause
PSPS	Public Safety Power Shutoff
PTAM	Post Test-year Adjustment Mechanism
PTC	Production Tax Credit
PUCN	Public Utilities Commission of Nevada
RCRA	Resource Conservation and Recovery Act
REC	Renewable Energy Credit
RFP	Request for Proposals
RPS	Renewable Portfolio Standards
RTO	Regional Transmission Organization
SCR	Selective Catalytic Reduction

SEC	U.S. Securities and Exchange Commission
SIP	State Implementation Plan
SO ₂	Sulfur Dioxide
TAM	Transition Adjustment Mechanism
UPSC	Utah Public Service Commission
WECC	Western Electricity Coordinating Council
WPSC	Wyoming Public Service Commission
WUTC	Washington Utilities and Transportation Commission
ZEC	Zero Emission Credit

Forward-Looking Statements

This report contains statements that do not directly or exclusively relate to historical facts. These statements are "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements can typically be identified by the use of forward-looking words, such as "will," "may," "could," "project," "believe," "anticipate," "expect," "estimate," "continue," "intend," "potential," "plan," "forecast" and similar terms. These statements are based upon the relevant Registrant's current intentions, estimates, assumptions, expectations and beliefs and are subject to risks, uncertainties and other important factors. Many of these factors are outside the control of each Registrant and could cause actual results to differ materially from those expressed or implied by such forward-looking statements. These factors include, among others:

- general economic, political and business conditions, as well as changes in, and compliance with, laws and regulations, including income tax reform, initiatives regarding deregulation and restructuring of the utility industry and reliability and safety standards, affecting the respective Registrant's operations or related industries;
- changes in, and compliance with, environmental laws, regulations, decisions and policies, whether directed towards protection of environmental resources, present and future climate considerations or social justice concerns that could, among other items, increase operating and capital costs, reduce facility output, accelerate facility retirements or delay facility construction or acquisition;
- the outcome of regulatory rate reviews and other proceedings conducted by regulatory agencies or other governmental and legal bodies and the respective Registrant's ability to recover costs through rates in a timely manner;
- changes in economic, industry, competition or weather conditions, as well as demographic trends, new technologies and various conservation, energy efficiency and private generation measures and programs, that could affect customer growth and usage, electricity and natural gas supply or the respective Registrant's ability to obtain long-term contracts with customers and suppliers;
- performance, availability and ongoing operation of the respective Registrant's facilities, including facilities not operated by the Registrants, due to the impacts of market conditions, outages and associated repairs, transmission constraints, weather, including wind, solar and hydroelectric conditions, and operating conditions;
- the effects of catastrophic and other unforeseen events, which may be caused by factors beyond the control of each respective Registrant or by a breakdown or failure of the Registrants' operating assets, including severe storms, floods, fires, extreme temperature events, wind events, earthquakes, explosions, landslides, an electromagnetic pulse, mining incidents, costly litigation, wars, terrorism, pandemics, embargoes, and cyber security attacks, data security breaches, disruptions, or other malicious acts;
- the risks and uncertainties associated with wildfires that have occurred, are occurring or may occur in the respective Registrant's service territory; the damage caused by such wildfires; the extent of the respective Registrant's liability in connection with such wildfires (including the risk that the respective Registrant may be found liable for damages regardless of fault); investigations into such wildfires; the outcomes of any legal proceedings, demands or similar actions initiated against the respective Registrant; the risk that the respective Registrant is not able to recover losses from insurance or through rates; and the effect of such wildfires, investigations and legal proceedings on the respective Registrant's financial condition and reputation;
- the outcomes of legal or other actions and the effects of amounts to be paid to complainants as a result of settlements or final legal determinations associated with the Wildfires, which could have a material adverse effect on PacifiCorp's financial condition and could limit PacifiCorp's ability to access capital on terms commensurate with historical transactions or at all and could impact PacifiCorp's liquidity, cash flows and capital expenditure plans;
- the respective Registrant's ability to reduce wildfire threats and improve safety, including the ability to comply with the targets and metrics set forth in its wildfire mitigation plans; to retain or contract for the workforce necessary to execute its wildfire mitigation plans; the effectiveness of its system hardening; ability to achieve vegetation management targets; and the cost of these programs and the timing and outcome of any proceeding to recover such costs through rates;
- the ability to economically obtain insurance coverage, or any insurance coverage at all, sufficient to cover losses arising from catastrophic events, such as wildfires;
- a high degree of variance between actual and forecasted load or generation that could impact a Registrant's hedging strategy and the cost of balancing its generation resources with its retail load obligations;
- changes in prices, availability and demand for wholesale electricity, coal, natural gas, other fuel sources and fuel transportation that could have a significant impact on generating capacity and energy costs;

- the financial condition, creditworthiness and operational stability of the respective Registrant's significant customers and suppliers;
- changes in business strategy or development plans;
- availability, terms and deployment of capital, including reductions in demand for investment-grade commercial paper, debt securities and other sources of debt financing and volatility in interest rates and credit spreads;
- changes in the respective Registrant's credit ratings, changes in rating methodology and placement on negative outlook or credit watch;
- risks relating to nuclear generation, including unique operational, closure and decommissioning risks;
- hydroelectric conditions and the cost, feasibility and eventual outcome of hydroelectric relicensing proceedings;
- the impact of certain contracts used to mitigate or manage volume, price and interest rate risk, including increased collateral requirements, and changes in commodity prices, interest rates and other conditions that affect the fair value of certain contracts;
- the impact of inflation on costs and the ability of the respective Registrants to recover such costs in regulated rates;
- fluctuations in foreign currency exchange rates, primarily the British pound and the Canadian dollar;
- increases in employee healthcare costs;
- the impact of investment performance, certain participant elections such as lump sum distributions and changes in interest rates, legislation, healthcare cost trends, mortality, morbidity on pension and other postretirement benefits expense and funding requirements;
- changes in the residential real estate brokerage, mortgage and franchising industries, regulations that could affect brokerage, mortgage and franchising transactions and the outcomes of legal or other actions and the effects of amounts to be repaid to complainants as a result of settlements or final legal determinations;
- the ability to successfully integrate future acquired operations into a Registrant's business;
- the impact of supply chain disruptions and workforce availability on the respective Registrant's ongoing operations and its ability to timely complete construction projects;
- unanticipated construction delays, changes in costs, delays in or the inability to receive required permits and authorizations, including the impact of new regulations or actions taken to implement or rescind U.S. federal executive orders, ability to fund capital projects and other factors that could affect future facilities and infrastructure additions;
- the availability and price of natural gas in applicable geographic regions and demand for natural gas supply;
- the impact of new accounting guidance or changes in current accounting estimates and assumptions on the financial results of the respective Registrants; and
- other business or investment considerations that may be disclosed from time to time in the Registrants' filings with the SEC or in other publicly disseminated written documents.

Further details of the potential risks and uncertainties affecting the Registrants are described in the Registrants' filings with the SEC, including Item 1A and other discussions contained in this Form 10-K. Each Registrant undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The foregoing factors should not be construed as exclusive.

PART I

Item 1. Business

GENERAL

BHE, a wholly owned subsidiary of Berkshire Hathaway, is a holding company headquartered in Iowa that has investments in a highly diversified portfolio of locally managed and operated businesses principally engaged in the energy industry. The Company's operations are organized as eight business segments: PacifiCorp, MidAmerican Funding (which primarily consists of MidAmerican Energy), NV Energy (which primarily consists of Nevada Power and Sierra Pacific), Northern Powergrid (which primarily consists of Northern Powergrid (Northeast) plc and Northern Powergrid (Yorkshire) plc), BHE Pipeline Group (which primarily consists of BHE GT&S, Northern Natural Gas and Kern River), BHE Transmission (which consists of BHE Canada (which primarily consists of AltaLink) and BHE U.S. Transmission), BHE Renewables and HomeServices. BHE, through these locally managed and operated businesses, has investments in four utility companies in the U.S. serving customers in 11 states, two electricity distribution companies in Great Britain, five interstate natural gas pipeline companies in the U.S., one of which owns an LNG export, import and storage facility, an electric transmission business in Canada, interests in electric transmission businesses in the U.S., a renewable energy business primarily investing in wind, solar, geothermal and hydroelectric projects, one of the largest residential real estate brokerage firms and residential real estate brokerage franchise networks in the U.S.

BHE's highly diversified portfolio of primarily regulated businesses generate, transmit, store, distribute and supply energy and serve customers and end-users across geographically diverse service territories, including 28 states located throughout the U.S. and in Great Britain and Canada.

- Approximately 80% of the Company's consolidated adjusted earnings on common shares during 2024 was generated from rate-regulated businesses.
- The Utilities serve 5.3 million electric and natural gas customers in 11 states in the U.S., Northern Powergrid serves 4.0 million end-users in northern England and AltaLink serves approximately 85% of Alberta, Canada's population.
- As of December 31, 2024, the Company owns approximately 37,400 MWs of generation capacity in operation and under construction:
 - Approximately 31,300 MWs of generation capacity is owned by its regulated electric utility businesses;
 - Approximately 6,100 MWs of generation capacity is owned by its nonregulated subsidiaries, the majority of which provides power to utilities under long-term contracts;
 - Owned generation capacity in operation and under construction consists of 42% wind and solar, 33% natural gas, 20% coal, 4% hydroelectric and geothermal and 1% nuclear and other; and,
 - Cumulative investments in (i) owned wind, solar and geothermal generation facilities of \$35.4 billion and (ii) wind projects sponsored by third parties, commonly referred to as tax equity investments, of \$7.3 billion.
- The Company owns approximately 36,800 miles of electric transmission lines, a 50% interest in ETT that has approximately 2,100 miles of electric transmission lines, approximately 178,400 miles of electric distribution lines and approximately 2,900 substations.
- The BHE Pipeline Group operates approximately 21,000 miles of pipeline with a design capacity of approximately 21.5 Bcf of natural gas per day, transported approximately 14% of the total natural gas consumed in the U.S. during 2024 and owns assets in 27 states. The BHE Pipeline Group also operates 22 natural gas storage facilities with a total working gas capacity of 515.6 Bcf and an LNG export, import and storage facility.
- HomeServices closed approximately \$138.8 billion of home sales in 2024 and has brokerage, mortgage and franchise services in all 50 states. HomeServices' franchise business has 270 franchisees primarily in the U.S.

Human Capital

The Registrants are committed to attracting, retaining and developing the highest quality of employees; maintaining a safe, diverse and inclusive work environment; offering competitive compensation and benefit programs; and providing employees with opportunities for growth and development.

Employees

As of December 31, 2024, the Company had approximately 23,800 employees, consisting of approximately 14,600 (61%) electric and natural gas operations employees, approximately 5,400 (23%) real estate services employees and approximately 3,800 (16%) corporate services employees. HomeServices has approximately 37,700 real estate agents who are independent contractors. As of December 31, 2024, approximately 9,000 employees were covered by union contracts. The majority of the union employees are employed by the Utilities and are represented by the International Brotherhood of Electrical Workers, the Utility Workers Union of America, the United Utility Workers Association and the International Brotherhood of Boilermakers.

Safety and Security

Safety and security are integral to the Registrants' culture and will always be a part of the Registrants' top priorities. The Registrants' safety, cyber and physical security programs are built on personal ownership, compliance with standards, accountability for performance, and continuous improvement. The Registrants provide training to ensure that all employees understand the risks and have thorough and specific knowledge to protect themselves, as well as the Registrants' assets, information and operations.

The Registrants use the recordable incident rate to measure employee safety. The recordable incident rate is defined as the number of work-related injuries per 100 full-time workers during a given year. The recordable incident rates for each of the Registrants for the year ended December 31, 2024 are included below:

Recordable Incident Rate:

PacifiCorp	0.74
MidAmerican Energy	0.88
Nevada Power	0.52
Sierra Pacific	0.75
Eastern Energy Gas	0.13
EGTS	0.16
BHE Overall	0.50

Compensation and Benefits

The Registrants' commitment to employees is further demonstrated through competitive compensation and benefits and by providing opportunities for personal growth and career development. In addition to market-based salary, the Registrants' compensation packages include incentive programs to recognize and reward outstanding performance. The Registrants' benefits programs are designed to meet the diverse needs of employees and their families and include among other benefits:

- A comprehensive and flexible benefits package that includes medical, dental and vision coverage; employee assistance programs; pre-tax flexible spending accounts; and adoption assistance;
- Income protection that includes options for short- and long-term disability coverage and life insurance;
- Retirement planning that includes a retirement savings plan 401(k) and a variety of employee and employer contribution and matching options;
- Family Medical Leave as well as paid time off, bereavement leave and holiday benefits; and
- Career development opportunities that provide access to a variety of learning programs and career development support, including tuition reimbursement or assistance.

BHE was incorporated under the laws of the state of Iowa in 1999 and its principal executive offices are located at 1615 Locust Street, Des Moines, Iowa 50309-3037, its telephone number is (515) 242-4300 and its internet address is www.brkenenergy.com.

PACIFICORP

General

PacifiCorp, an indirect wholly owned subsidiary of BHE, is a U.S. regulated electric utility company headquartered in Oregon that serves approximately 2.1 million retail electric customers in portions of Utah, Oregon, Wyoming, Washington, Idaho and California. PacifiCorp is principally engaged in the business of generating, transmitting, distributing and selling electricity. PacifiCorp's combined service territory covers approximately 141,500 square miles and includes diverse regional economies across six states. No single segment of the economy dominates the combined service territory, which helps mitigate PacifiCorp's exposure to economic fluctuations. In the eastern portion of the service territory, consisting of Utah, Wyoming and southeastern Idaho, the principal industries are manufacturing, mining or extraction of natural resources, agriculture, technology, recreation and government. In the western portion of the service territory, consisting of Oregon, southern Washington and northern California, the principal industries are agriculture, manufacturing, forest products, food processing, technology, government and primary metals. In addition to retail sales, PacifiCorp buys and sells electricity on the wholesale market with other utilities, energy marketing companies, financial institutions and other market participants to balance and optimize the economic benefits of electricity generation, retail customer loads and existing wholesale transactions. Certain PacifiCorp subsidiaries support its electric utility operations by providing coal mining services.

PacifiCorp's operations are conducted under numerous franchise agreements, certificates, permits and licenses obtained from federal, state and local authorities. The average term of these franchise agreements is approximately 21 years. Several of these franchise agreements allow the municipality the right to seek amendment to the franchise agreement at a specified time during the term. PacifiCorp generally has an exclusive right to serve electric customers within its service territories and, in turn, has an obligation to provide electric service to those customers. In return, the state utility commissions have established rates on a cost-of-service basis, which are designed to allow PacifiCorp an opportunity to recover its costs of providing services and to earn a reasonable return on its investments.

PacifiCorp was incorporated under the laws of the state of Oregon in 1989. Its principal executive offices are located at 825 N.E. Multnomah Street, Portland, Oregon 97232, its telephone number is (888) 221-7070 and its internet address is www.pacificorp.com. PacifiCorp delivers electricity to customers in Utah, Wyoming and Idaho under the trade name Rocky Mountain Power and to customers in Oregon, Washington and California under the trade name Pacific Power.

Effective February 10, 2025, all shares of PacifiCorp's common stock and preferred stock are indirectly held by BHE.

Regulated Electric Operations

Customers

The GWhs and percentages of electricity sold to PacifiCorp's retail customers by jurisdiction for the years ended December 31 were as follows:

	2024		2023		2022	
Utah	27,138	46 %	26,062	46 %	26,110	46 %
Oregon	13,991	24	13,949	25	13,701	24
Wyoming	8,759	15	8,579	15	8,666	15
Washington	4,112	7	3,850	7	4,181	7
Idaho	3,728	7	3,496	6	3,707	7
California	747	1	760	1	799	1
Total	58,475	100 %	56,696	100 %	57,164	100 %

Electricity sold to PacifiCorp's retail and wholesale customers by class of customer and the average number of retail customers for the years ended December 31 were as follows:

	2024		2023		2022	
GWhs sold:						
Residential	18,253	30 %	18,159	31 %	18,425	30 %
Commercial	21,585	36	20,491	34	19,570	32
Industrial	17,101	28	16,705	28	17,622	28
Other	1,536	2	1,341	2	1,547	2
Total retail	58,475	96	56,696	95	57,164	92
Wholesale	2,280	4	2,911	5	4,836	8
Total GWhs sold	60,755	100 %	59,607	100 %	62,000	100 %

Average number of retail customers (in thousands):

Residential	1,838	87 %	1,806	87 %	1,775	87 %
Commercial	230	11	227	11	225	11
Industrial	9	1	9	1	9	1
Other	27	1	27	1	28	1
Total	2,104	100 %	2,069	100 %	2,037	100 %

Variations in weather, economic conditions and various conservation, energy efficiency and private generation measures and programs can impact customer energy requirements. Wholesale sales are impacted by market prices for energy relative to the incremental cost to generate electricity.

The annual hourly peak customer demand, which represents the highest demand on a given day and at a given hour, occurs in the summer when air conditioning and irrigation systems are heavily used. During the summer months of 2024, 2023 and 2022, PacifiCorp's hourly peak demand was 11,156, 10,802 and 11,017 MWs, respectively. Peak demand in the winter occurs due to heating requirements. During the winter months of 2024, 2023 and 2022, PacifiCorp's hourly peak demand was 9,139, 8,998 and 9,026 MWs, respectively.

Generating Facilities and Fuel Supply

PacifiCorp has ownership interests in a diverse portfolio of generating facilities. The following table presents certain information regarding PacifiCorp's owned generating facilities as of December 31, 2024:

Generating Facility	Location	Energy Source	Installed / Repowered ⁽¹⁾ or Converted ⁽²⁾	Facility Net Capacity (MWs) ⁽³⁾	Net Owned Capacity (MWs) ⁽³⁾
COAL:					
Hunter Nos. 1, 2 and 3	Castle Dale, UT	Coal	1978-1983	1,363	1,158
Huntington Nos. 1 and 2	Huntington, UT	Coal	1974-1977	909	909
Dave Johnston Nos. 1, 2, 3 and 4	Glenrock, WY	Coal	1959-1972	745	745
Jim Bridger Nos. 3 and 4	Rock Springs, WY	Coal	1976-1979	1,049	700
Naughton Nos. 1 and 2	Kemmerer, WY	Coal	1963-1968	357	357
Wyodak	Gillette, WY	Coal	1978	332	266
Craig Nos. 1 and 2	Craig, CO	Coal	1979-1980	837	161
Colstrip Nos. 3 and 4	Colstrip, MT	Coal	1984-1986	1,480	148
Hayden Nos. 1 and 2	Hayden, CO	Coal	1965-1976	441	77
				7,513	4,521
NATURAL GAS:					
Jim Bridger Nos. 1 and 2	Rock Springs, WY	Natural gas	1974-1975 / 2024	1,070	713
Lake Side 2	Vineyard, UT	Natural gas/steam	2014	631	631
Lake Side	Vineyard, UT	Natural gas/steam	2007	546	546
Currant Creek	Mona, UT	Natural gas/steam	2005-2006	524	524

Generating Facility	Location	Energy Source	Installed / Repowered ⁽¹⁾ or Converted ⁽²⁾	Facility Net Capacity (MWs) ⁽³⁾	Net Owned Capacity (MWs) ⁽³⁾
Chehalis	Chehalis, WA	Natural gas/steam	2003	477	477
Naughton No. 3	Kemmerer, WY	Natural gas	1971 / 2020	290	290
Gadsby Steam	Salt Lake City, UT	Natural gas	1951-1955 / 1991	238	238
Hermiston	Hermiston, OR	Natural gas/steam	1996	461	231
Gadsby Peakers	Salt Lake City, UT	Natural gas	2002	119	119
				4,356	3,769
WIND:					
TB Flats	Medicine Bow, WY	Wind	2020-2021	500	500
Ekola Flats	Medicine Bow, WY	Wind	2020	250	250
Pryor Mountain	Bridger, MT	Wind	2020-2021	240	240
Marengo	Dayton, WA	Wind	2007-2008 / 2020	234	234
Cedar Springs II	Douglas, WY	Wind	2020	199	199
Glenrock	Glenrock, WY	Wind	2008-2009 / 2019	139	139
Seven Mile Hill	Medicine Bow, WY	Wind	2008 / 2019	119	119
Dunlap Ranch	Medicine Bow, WY	Wind	2010 / 2020	111	111
Leaning Juniper	Arlington, OR	Wind	2006 / 2019	100	100
Rolling Hills	Glenrock, WY	Wind	2009 / 2019	100	100
High Plains	McFadden, WY	Wind	2009 / 2019	99	99
Goodnoe Hills	Goldendale, WA	Wind	2008 / 2019	94	94
Rock Creek I	Arlington, WY	Wind	2024	61	61
Rock River I	Rock River, WY	Wind	2024	50	50
Foote Creek I	Arlington, WY	Wind	1999 / 2021	41	41
McFadden Ridge	McFadden, WY	Wind	2009 / 2019	28	28
Foote Creek III	Arlington, WY	Wind	2023	25	25
Foote Creek IV	Arlington, WY	Wind	2023	17	17
				2,407	2,407
HYDROELECTRIC:					
Lewis River System	WA	Hydroelectric	1931-1958	578	578
North Umpqua River System	OR	Hydroelectric	1950-1956	204	204
Bear River System	ID, UT	Hydroelectric	1908-1984	105	105
Rogue River System	OR	Hydroelectric	1912-1957	52	52
Minor hydroelectric facilities	Various	Hydroelectric	1895-1986	32	32
				971	971
OTHER:					
Blundell	Milford, UT	Geothermal	1984, 2007	32	32
				32	32
Total Available Generating Capacity				15,279	11,700
PROJECTS UNDER CONSTRUCTION:					
Various projects ⁽⁴⁾	Wyoming	Wind	Est. 2025	531	531
				15,810	12,231

(1) Repowered dates are associated with component replacements on existing wind-powered generating facilities commonly referred to by the U.S. Internal Revenue Service ("IRS") as repowering. IRS rules provide for re-establishment of the PTCs for an existing wind-powered generating facility upon the replacement of a significant portion of its components. If the degree of component replacement in such projects meets IRS guidelines, PTCs are re-established for 10 years beginning with the date the repowered facility is placed in-service.

(2) Converted dates are associated with the in-service date of coal-fueled generating facilities converted to natural gas-fueled facilities.

(3) Facility Net Capacity represents the lesser of nominal ratings or any limitations under applicable interconnection, power purchase, or other agreements for intermittent resources and the total net dependable capability available during summer conditions for all other units. An intermittent resource's nominal rating is the manufacturer's contractually specified capability (in MWs) under specified conditions. Net Owned Capacity indicates PacifiCorp's ownership of Facility Net Capacity.

- (4) Includes portions of Rock Creek I that remain under construction and are expected to be placed in-service in 2025, as well as Rock Creek II that is expected to be placed in-service in 2025.

PacifiCorp has a 2 MW battery energy storage system under construction in Oregon which it expects to place in-service in 2025.

PacifiCorp has entered into multiple electricity contracts from specified resources that it considers part of the total available generating capacity. The following table presents PacifiCorp's contractual right to capacity regarding generation sources of purchased electricity contracts as of December 31, 2024:

Electricity Contract Energy Source	Contractual Capacity MWs
Solar	2,343
Wind	1,766
Hydroelectric	627
Other renewable	141
Total renewable	4,877
Natural gas and other	191
Total contractual capacity	5,068

The following table shows the percentages of PacifiCorp's total energy supplied by energy source for the years ended December 31:

	2024	2023	2022
Coal	28 %	34 %	43 %
Natural gas	26	22	21
Wind ⁽¹⁾	11	10	11
Hydroelectric and other ⁽¹⁾	4	5	5
Total energy generated	69	71	80
Energy purchased - long-term contracts (renewable) ⁽¹⁾	19	16	15
Energy purchased - short-term contracts and other	11	12	5
Energy purchased - long term contracts (non-renewable)	1	1	—
	100 %	100 %	100 %

- (1) All or some of the renewable energy attributes associated with generation from these sources may be: (a) used in future years to comply with RPS or other regulatory requirements, (b) sold to third parties in the form of RECs or other environmental commodities, or (c) excluded from energy purchased.

PacifiCorp is required to have resources available to continuously meet its customer needs and reliably operate its electric system. The percentage of PacifiCorp's energy supplied by energy source varies from year to year and is subject to numerous operational, economic and environmental factors such as planned and unplanned outages; fuel commodity prices; fuel availability; fuel transportation costs; weather, including temperature, hydrologic conditions, wind and sun; legislative and environmental considerations; transmission constraints; wholesale market prices of electricity and other factors. PacifiCorp evaluates these factors continuously in order to facilitate dispatch of its generating facilities. When factors for one energy source are less favorable, PacifiCorp places more reliance on other energy sources. For example, PacifiCorp can generate more electricity using its low-cost wind-powered and hydroelectric generating facilities when factors associated with these facilities are favorable. In addition to meeting its customers' energy needs, PacifiCorp is required to maintain operating reserves on its system to mitigate the impacts of unplanned outages or other disruption in supply, and to meet intra-hour changes in load and resource balance. This operating reserve requirement is dispersed across PacifiCorp's generation portfolio on a least-cost basis based on the operating characteristics of the portfolio. Operating reserves may be held on hydroelectric, coal-fueled, natural gas-fueled or certain types of interruptible load. PacifiCorp manages certain risks relating to its supply of electricity and fuel requirements by entering into various contracts, which may be accounted for as derivatives and may include forwards, options, swaps and other agreements. Refer to "General Regulation" in Item 1 of this Form 10-K for a discussion of energy cost recovery by jurisdiction and to PacifiCorp's Item 7A in this Form 10-K for a discussion of commodity price risk and derivative contracts.

Coal

PacifiCorp has interests in coal mines that support its coal-fueled generating facilities and jointly operates the Bridger surface coal mine. These mines supplied 18%, 18% and 21% of PacifiCorp's total coal requirements during the years ended December 31, 2024, 2023 and 2022, respectively.

Most of PacifiCorp's coal reserves are held through agreements with the federal Bureau of Land Management and certain states and private parties. The agreements generally have multi-year terms that may be renewed or extended and require payment of rents and royalties. In addition, federal and state regulations require that comprehensive environmental protection and reclamation standards be met during the course of mining operations and upon completion of mining activities.

Coal reserve estimates are subject to adjustment as a result of the development of additional engineering and geological data, new mining technology and changes in regulation and economic factors affecting the utilization of such reserves. Recoverability by surface mining methods typically ranges from 90% to 95%.

PacifiCorp believes it will be able to purchase coal under both long- and short-term third-party contracts to supply the remaining coal requirements at its coal-fueled generating facilities over their currently expected remaining useful lives. PacifiCorp has experienced higher costs to procure coal supply for its Utah coal-fueled generating facilities as a result of reduced suppliers, fires in third-party mines, coal supplier solvency and financing issues, labor shortages, transportation limitations, delays in federal leasing processes, and production delays due to unfavorable geologic conditions.

Natural Gas

PacifiCorp uses natural gas as fuel for its generating facilities that use combined-cycle, simple-cycle and steam turbines. Oil and natural gas are also used for igniter fuel and standby purposes. These sources are presently in adequate supply and available to meet PacifiCorp's needs.

PacifiCorp enters into forward natural gas purchases at fixed or indexed market prices. PacifiCorp purchases natural gas in the spot market with both fixed and indexed market prices for physical delivery to fulfill any fuel requirements not already satisfied through forward purchases of natural gas and sells natural gas in the spot market for the disposition of any excess supply if the forecasted requirements of its natural gas-fueled generating facilities decrease. PacifiCorp also utilizes financial swap contracts to mitigate price risk associated with its forecasted fuel requirements.

Wind

PacifiCorp has pursued wind-powered generating facilities as a viable, economical and environmentally prudent means of supplying electricity and to comply with laws and regulations. Wind-powered generating facilities have low to no emissions. The generation from PacifiCorp's wind-powered generating fleet, comprised of newly constructed and recently repowered wind-powered generating facilities, qualifies for federal PTCs for 10 years beginning with the date the new or repowered facility is placed in-service.

Hydroelectric and Other Renewable Resources

The amount of electricity PacifiCorp is able to generate from its hydroelectric generating facilities depends on a number of factors, including snowpack in the mountains upstream of its hydroelectric generating facilities, reservoir storage, precipitation in its watersheds, generating unit availability and restrictions imposed by oversight bodies due to competing water management objectives.

PacifiCorp operates the majority of its hydroelectric generating portfolio under long-term licenses. The FERC regulates 98% of the net capacity of this portfolio through 14 individual licenses, which have terms of 30 to 50 years. The licenses for these hydroelectric generating facilities expire at various dates through 2061. A portion of this portfolio is licensed under the Oregon Hydroelectric Act. For discussion of PacifiCorp's hydroelectric relicensing activities, including updated information regarding the Klamath River hydroelectric system, refer to Note 16 of the Notes to Consolidated Financial Statements of Berkshire Hathaway Energy in Item 8 of this Form 10-K and Note 14 of the Notes to Consolidated Financial Statements of PacifiCorp in Item 8 of this Form 10-K.

Wholesale Activities

PacifiCorp purchases and sells electricity in the wholesale markets as needed to balance its generation with its retail load obligations. PacifiCorp may also purchase electricity in the wholesale markets when it is more economical than generating electricity from its own facilities and may sell surplus electricity in the wholesale markets when it can do so economically. When prudent, PacifiCorp enters into financial swap contracts and forward electricity sales and purchases for physical delivery at fixed prices to reduce its exposure to changes in electricity prices.

Energy Imbalance Market

PacifiCorp and the California ISO implemented an EIM in November 2014, which delivers customer benefits by leveraging automation and resource diversity to result in more efficient dispatch of a larger and more diverse pool of resources, more effectively integrates renewables and enhances reliability through improved situational awareness and responsiveness. The EIM expands the real-time component of the California ISO's market technology to optimize and balance electricity supply and demand every five minutes across the EIM footprint. The EIM is voluntary and available to all balancing authorities in the western U.S. EIM market participants submit bids to the California ISO market operator before each hour for each generating resource they choose to be dispatched by the market. Each bid is comprised of a dispatchable operating range, ramp rate and prices across the operating range. The California ISO market operator uses sophisticated technology to select the least-cost resources to meet demand and send simultaneous dispatch signals to every participating generator across the EIM footprint every five minutes. In addition to generation resource bids, the California ISO market operator also receives continuous real-time updates of the transmission grid network, meteorological and load forecast information that it uses to optimize dispatch instructions. Customer benefits are expected to increase further with renewable resource expansion and as more entities join the EIM, bringing incremental resource diversity. PacifiCorp is working with the California ISO to join the California ISO Extended Day-Ahead Market ("EDAM") in 2026. The EDAM is a voluntary day-ahead electricity market designed to deliver significant reliability, economic, and environmental benefits to balancing areas and utilities throughout the West.

Transmission and Distribution

PacifiCorp operates one balancing authority area in the western portion of its service territory ("PacifiCorp-West") and one balancing authority area in the eastern portion of its service territory ("PacifiCorp-East"). A balancing authority area is a geographic area with transmission systems that control generation to maintain schedules with other balancing authority areas and ensure reliable operations. In operating the balancing authority areas, PacifiCorp is responsible for continuously balancing electricity supply and demand by dispatching generating resources and interchange transactions so that generation internal to the balancing authority area, plus net imported power, matches customer loads. Deliveries of energy over PacifiCorp's transmission system are managed and scheduled in accordance with the FERC's requirements.

PacifiCorp's transmission system is part of the Western Interconnection, which includes the interconnected transmission systems of 14 western states, two Canadian provinces and parts of Mexico. PacifiCorp's transmission system, together with contractual rights on other transmission systems, enables PacifiCorp to integrate and access generation resources to meet its customer load requirements. PacifiCorp's transmission and distribution systems included approximately 17,500 miles of transmission lines in 10 states, 66,900 miles of distribution lines and 900 substations as of December 31, 2024.

PacifiCorp's transmission and distribution system is managed on a coordinated basis to obtain maximum load-carrying capability and efficiency. Portions of PacifiCorp's transmission and distribution systems are located:

- On property owned or used through agreements by PacifiCorp;
- Under or over streets, alleys, highways and other public places, the public domain and national forests and state and federal lands under franchises, easements or other rights that are generally subject to termination;
- Under or over private property as a result of easements obtained primarily from the title holder of record; or
- Under or over Native American reservations through agreements with the U.S. Secretary of Interior or Native American tribes.

It is possible that some of the easements and the property over which the easements were granted may have title defects or may be subject to mortgages or liens existing at the time the easements were acquired.

PacifiCorp's Energy Gateway Transmission Expansion Program represents a major transmission project that built over 1,000 miles of new high-voltage transmission lines, primarily in Wyoming, Utah, Idaho and Oregon. The Energy Gateway Transmission Expansion Program included: (a) the 135-mile, 345-kV transmission line between the Terminal substation near the Salt Lake City Airport and the Populus substation in Downey, Idaho, placed in-service in 2010; (b) the 100-mile, 345/500-kV transmission line between the Mona substation in central Utah and the Oquirrh substation in the Salt Lake Valley, placed in-service in 2013; (c) the 170-mile, 345-kV transmission line between the Sigurd substation in central Utah and the Red Butte substation in southwest Utah, placed in-service in 2015; (d) the 140-mile, 500-kV transmission line between the Aeolus substation near Medicine Bow, Wyoming and the Jim Bridger generating facility, placed in-service in 2020; (e) the 416-mile, 500-kV high-voltage transmission line between the Aeolus substation and the Clover substation near Mona, Utah, placed in-service in 2024; (f) the 59-mile, 230-kV high-voltage transmission line between the Windstar substation near Glenrock, Wyoming and the Aeolus substation, placed in-service in 2024; and (g) the 14-mile, 345-kV high-voltage transmission line between the Oquirrh substation and the Terminal substation, placed in-service in 2024. The transmission line segments are intended to: (a) address customer load growth; (b) improve system reliability; (c) reduce transmission system constraints; (d) provide access to diverse generation resources, including renewable and zero carbon resources; and (e) improve the flow of electricity throughout PacifiCorp's six-state service area. Through December 31, 2024, \$4.8 billion, including AFUDC, had been placed in-service.

Wildfire Mitigation Plans

PacifiCorp has developed detailed wildfire mitigation plans for each of the six states in which it operates. Wildfire mitigation plans are filed annually with the OPUC, the CPUC and the UPSC. Although not required, a wildfire mitigation plan is provided annually to the WUTC. In 2024, wildfire mitigation plans were also provided to the IPUC and the WPSC with a similar schedule of providing annual future updates. These plans include capital investment in asset hardening and meteorological systems, the implementation of risk modeling tools and PacifiCorp's ongoing enhanced safety settings, inspections, vegetation management, PSPS and wildfire encroachment programs and policies.

Asset Hardening

PacifiCorp has and continues to invest in rebuilding overhead lines with covered conductor and in some cases has converted overhead distribution lines to underground. These system hardening efforts reduce the exposure of PacifiCorp's lines to interference from trees and other objects. Covered conductor helps mitigate the risk of fault-caused electrical arcs that could cause an ignition. Overall, mitigated overhead lines help reduce ignition risk and improve reliability during storms or periods of significant wildfire risk.

Approximately 9,700 miles, or 15%, of PacifiCorp's distribution lines are in fire high consequence areas ("FHCA"), covering approximately 8% of its service territory and approximately 10% of its customer base. Approximately 2,000 miles of transmission lines are in the FHCA. In 2024, the process for updating the risk modeling for the identification of the FHCA was completed resulting in an expansion of FHCA.

As of December 31, 2024, all 2,000 miles of transmission lines in the FHCA are mitigated by system relay protection schemes. All 9,700 miles of distribution lines in the FHCA include some form of mitigation including:

- 5,300 miles, or 55%, with bare conductor mitigated by system relay protection schemes;
- 500 miles, or 5%, with new covered conductor; and
- 3,900 miles, or 40%, underground.

The on-going asset hardening of the FHCA is a priority for PacifiCorp and a key part of the developed wildfire mitigation plans.

Refer to "Future Uses of Cash" in Item 7 of this Form 10-K for further discussion of PacifiCorp's wildfire mitigation related capital expenditures, including asset hardening.

Enhanced Safety Settings

Enhanced safety settings are available across PacifiCorp's service territory, including the ongoing installation of new microprocessor relays to detect faults occurring on transmission and distribution lines in the FHCA and de-energize the line quickly limiting the arc-energy and potential for wildfire ignition. Field reclosers are being upgraded with similar fault detection capability in the FHCA.

Meteorology and Risk Modeling

PacifiCorp has installed over 600 weather stations that monitor weather conditions and model the impact to the electrical infrastructure. These weather stations utilized by the weather forecasting team servicing PacifiCorp's service territory provide PacifiCorp with the ability to forecast weather and fire risk impact data twice daily. PacifiCorp will continue to install additional weather stations to refine weather modeling in areas where geographic terrain conditions require a dense network of weather stations in order to provide the necessary granular data.

Asset Inspection Program

PacifiCorp conducts an annual inspection of overhead facilities within the FHCA with an accelerated correction timeline for any conditions noted. A detailed inspection of facilities is conducted every five years, which is twice as often as areas outside the FHCA.

Vegetation Management

PacifiCorp's vegetation management program includes annual vegetation inspections and ground clearing of equipment poles in the FHCA along with three-year trimming cycles in place, including in Oregon and California where fire hazard risk is highest.

Public Safety Power Shutoff and Wildfire Encroachment Policy

A PSPS is used as a preventative measure during periods of extreme wildfire risk where the electrical network is de-energized proactively under certain conditions. In determining whether to initiate a PSPS, PacifiCorp works with local public safety authorities in consideration of data from meteorological systems and forecasting tools. PacifiCorp also has a wildfire encroachment policy under which it will de-energize its lines when a known wildfire is within a specified distance of its assets. PSPS is an increasingly common practice for utilities to use as part of wildfire mitigation.

Future Generation, Conservation and Energy Efficiency

Energy Supply Planning

As required by certain state regulations, PacifiCorp uses an IRP to develop a long-term resource plan to ensure that PacifiCorp can continue to provide reliable and cost-effective electric service to its customers while maintaining compliance with existing and evolving environmental laws and regulations. The IRP process identifies the amount and timing of PacifiCorp's expected future resource needs, accounting for planning uncertainty, risks, reliability, state energy policies and other factors. The IRP is prepared following a public process, which provides an opportunity for stakeholders to participate in PacifiCorp's resource planning process. PacifiCorp files its IRP biennially with the state commissions in each of the six states where PacifiCorp operates. Five states indicate whether the IRP meets the state commission's IRP standards and guidelines, a process referred to as "acknowledgment" in some states. Acknowledgment by a state commission does not address recovery or prudence of resources ultimately selected.

In April 2024, PacifiCorp filed its 2023 IRP Update in Utah, Oregon, Wyoming and Idaho. In Washington, this filing was submitted as informational. Concurrent with the filing of the 2023 IRP Update, PacifiCorp filed an Oregon Planning Supplement to address additional requirements related to the Oregon Clean Energy Plan.

In December 2024, PacifiCorp filed its Draft 2025 IRP consistent with Washington regulatory requirements. At the same time, the Draft 2025 IRP was made publicly available to stakeholders and commissions in all six PacifiCorp states. The Draft 2025 IRP is anticipated to be the focus of discussion in PacifiCorp's scheduled public input meetings in January and February 2025.

PacifiCorp's petition to the WUTC to approve an alternative IRP filing schedule has been partially accepted and will extend the existing timeline of the 2025 IRP filing by three months to align with the filing schedules of the other five states within PacifiCorp's six-state territory. Related 2025 IRP filing dates are also extended; however, the filing dates for Washington's Clean Energy Implementation Plan are unchanged.

PacifiCorp expects to maintain a March 31, 2025 filing date for the 2025 IRP.

Requests for Proposals

PacifiCorp issues individual RFPs to procure resources identified in the IRP or resources driven by customer demands and regulatory policy changes. The IRP and the RFPs provide for the identification and staged procurement of resources to meet load and state-specific compliance obligations. Depending upon the specific RFP, applicable laws and regulations may require PacifiCorp to file draft RFPs with the UPSC, the OPUC and the WUTC. Approval by the UPSC, the OPUC or the WUTC may be required depending on the nature of the RFPs.

PacifiCorp's most recent RFP, the 2022 All-Source ("2022AS") RFP, was issued to the market in April 2022. In September 2023, PacifiCorp suspended its 2022AS RFP and in April 2024, PacifiCorp provided notice that the 2022AS RFP was terminated. As indicated in the 2022AS RFP, PacifiCorp reserves the right, without limitation or qualification and in its sole discretion, to reject any or all bids, and to terminate or suspend the RFP in whole or in part at any time.

Key drivers behind PacifiCorp's decision to terminate the 2022AS RFP included:

- The EPA approval of Wyoming's state ozone transport plan.
- A federal court's stay of the EPA's proposed ozone transport rule.

These changes remove restrictions that limit energy production in the summer from natural gas and coal-fueled generating facilities in Wyoming and Utah.

The preferred portfolio in the 2023 IRP Update demonstrates that with limited procurement of battery resources in the near-term, which can be achieved outside of an RFP process, there is material benefit to customers to scaling down and delaying resource acquisition until after 2030. PacifiCorp's 2025 IRP, which is expected to be issued by March 31, 2025, will inform the next steps for incremental resource acquisition.

Energy Efficiency Programs

PacifiCorp has provided its customers with a comprehensive set of DSM programs since the 1970s. The programs are designed to reduce energy consumption and more effectively manage when energy is used, including management of seasonal peak loads. PacifiCorp offers services to customers such as energy engineering audits and information on how to improve the efficiency of their homes and businesses. To assist customers in investing in energy efficiency, PacifiCorp offers rebates or incentives encouraging the purchase and installation of high-efficiency equipment such as lighting, heating and cooling equipment, weatherization, motors, process equipment and systems, as well as incentives for energy project management, efficient building operations and efficient construction. Incentives are also paid to solicit participation in load management programs by residential, business and agricultural customers through programs such as PacifiCorp's residential and small commercial air conditioner load control program, battery control program and irrigation equipment load control programs. Although subject to prudence reviews, state regulations allow for recovery of costs incurred for the DSM programs through state-specific energy efficiency surcharges to retail customers or for recovery of costs through rates through PacifiCorp's general rate case process. During 2024, PacifiCorp spent \$218 million on these DSM programs, resulting in an estimated 652,986 MWhs of first-year energy savings and an estimated 470 MWs of peak load management. In addition to these DSM programs, PacifiCorp has load curtailment contracts with a number of large industrial customers that deliver up to 247 MWs of load reduction when needed, depending on the customers' actual operations. Costs associated with the large industrial load curtailment program are captured in the respective customers' retail special contracts.

Human Capital

Employees

As of December 31, 2024, PacifiCorp had approximately 5,200 employees, of which approximately 2,900 were covered by union contracts, principally with the International Brotherhood of Electrical Workers, the Utility Workers Union of America and the International Brotherhood of Boilermakers. For more information regarding PacifiCorp's human capital disclosures, refer to Item 1. Business - General section of this Form 10-K.

MIDAMERICAN FUNDING AND MIDAMERICAN ENERGY

General

MidAmerican Funding and MHC

MidAmerican Funding, a wholly owned subsidiary of BHE, is a holding company headquartered in Iowa that holds all of the outstanding common stock of MHC Inc. ("MHC"), which is a holding company that holds all of the common stock of MidAmerican Energy and Midwest Capital Group, Inc. ("Midwest Capital"). MidAmerican Funding and MidAmerican Energy are indirect consolidated subsidiaries of Berkshire Hathaway. MidAmerican Funding conducts no business other than activities related to its debt securities and investment in MHC. MHC conducts no business other than its investments in its subsidiaries. MidAmerican Energy is a substantial portion of MidAmerican Funding's and MHC's assets, revenue and earnings.

MidAmerican Funding was formed as a limited liability company under the laws of the state of Iowa in 1999 and its principal executive offices are located at 1615 Locust Street, Des Moines, Iowa 50309-3037 and its telephone number is (515) 242-4300.

MidAmerican Energy

MidAmerican Energy, an indirect wholly owned subsidiary of BHE, is a U.S. regulated electric and natural gas utility company headquartered in Iowa that serves 0.8 million retail electric customers in portions of Iowa, Illinois and South Dakota and 0.8 million retail and transportation natural gas customers in portions of Iowa, South Dakota, Illinois and Nebraska. MidAmerican Energy is principally engaged in the business of generating, transmitting, distributing and selling electricity and in distributing, selling and transporting natural gas. MidAmerican Energy's service territory covers approximately 11,000 square miles. MidAmerican Energy has a diverse customer base consisting of urban and rural residential customers and a variety of commercial and industrial customers. Principal industries served by MidAmerican Energy include electronic data storage; processing and sales of food products; manufacturing, processing and fabrication of primary metals, farm and other non-electrical machinery; cement and gypsum products; and government. In addition to retail sales and natural gas transportation, MidAmerican Energy sells electricity principally to markets operated by RTOs and natural gas to other utilities and market participants on a wholesale basis. MidAmerican Energy is a transmission-owning member of the MISO and participates in its capacity, energy and ancillary services markets.

MidAmerican Energy's regulated electric and natural gas operations are conducted under numerous franchise agreements, certificates, permits and licenses obtained from federal, state and local authorities. The franchise agreements, with various expiration dates, are typically for 20- to 25-year terms. Several of these franchise agreements give either party the right to seek amendment to the franchise agreement at one, two, three or four specified times during the term. MidAmerican Energy generally has an exclusive right to serve electric customers within its service territories and, in turn, has an obligation to provide electricity service to those customers. In return, the state utility commissions have established rates on a cost-of-service basis, which are designed to allow MidAmerican Energy an opportunity to recover its costs of providing services and to earn a reasonable return on its investment. In Illinois, MidAmerican Energy's regulated retail electric customers may choose their energy supplier.

MidAmerican Energy's operating revenue and operating income derived from the following business activities for the years ended December 31 were as follows (dollars in millions):

	2024		2023		2022	
Operating revenue:						
Regulated electric	\$ 2,584	80 %	\$ 2,673	79 %	\$ 2,988	74 %
Regulated gas	658	20	713	21	1,030	26
Other	9	—	7	—	7	—
Total operating revenue	<u>\$ 3,251</u>	<u>100 %</u>	<u>\$ 3,393</u>	<u>100 %</u>	<u>\$ 4,025</u>	<u>100 %</u>
Operating income:						
Regulated electric	\$ 310	76 %	\$ 471	90 %	\$ 372	85 %
Regulated gas	90	22	45	9	61	14
Other	8	2	5	1	5	1
Total operating income	<u>\$ 408</u>	<u>100 %</u>	<u>\$ 521</u>	<u>100 %</u>	<u>\$ 438</u>	<u>100 %</u>

MidAmerican Energy was incorporated under the laws of the state of Iowa in 1995 and its principal executive offices are located at 1615 Locust Street, Des Moines, Iowa 50309-3037, its telephone number is (515) 242-4300 and its internet address is www.midamericanenergy.com.

Regulated Electric Operations

Customers

The GWhs and percentages of electricity sold to MidAmerican Energy's retail customers by jurisdiction for the years ended December 31 were as follows:

	2024		2023		2022	
Iowa	27,918	93 %	27,554	93 %	27,024	92 %
Illinois	1,802	6	1,827	6	1,970	7
South Dakota	316	1	294	1	296	1
	<u>30,036</u>	<u>100 %</u>	<u>29,675</u>	<u>100 %</u>	<u>29,290</u>	<u>100 %</u>

Electricity sold to MidAmerican Energy's retail and wholesale customers by class of customer and the average number of retail customers for the years ended December 31 were as follows:

	2024		2023		2022	
GWhs sold:						
Residential	6,691	15 %	6,759	15 %	7,006	15 %
Commercial	3,926	9	3,992	9	4,017	9
Industrial	17,773	40	17,307	39	16,646	35
Other	1,646	4	1,617	3	1,621	3
Total retail	30,036	68	29,675	66	29,290	62
Wholesale	14,329	32	15,129	34	17,964	38
Total GWhs sold	44,365	100 %	44,804	100 %	47,254	100 %

Average number of retail customers (in thousands):						
Residential	710	86 %	703	86 %	697	86 %
Commercial	102	12	101	12	99	12
Industrial	2	—	2	—	2	—
Other	15	2	14	2	15	2
Total	829	100 %	820	100 %	813	100 %

Variations in weather, economic conditions and various conservation and energy efficiency measures and programs can impact customer energy requirements. Wholesale sales are primarily impacted by market prices for energy.

There are seasonal variations in MidAmerican Energy's electricity sales that are principally related to weather and the related use of electricity for air conditioning. Additionally, electricity sales are priced higher in the summer months compared to the remaining months of the year. As a result, 40% to 50% of MidAmerican Energy's regulated electric retail revenue is reported in the months of June through September.

A degree of concentration of sales exists with certain large electric retail customers. Sales to the 10 largest customers, from a variety of industries, comprised 27%, 26% and 25% of total retail electric sales in 2024, 2023 and 2022, respectively. Sales to electronic data storage customers included in the 10 largest customers comprised 23%, 20% and 18% of total retail electric sales in 2024, 2023 and 2022, respectively.

The annual hourly peak demand on MidAmerican Energy's electric system usually occurs as a result of air conditioning use during the cooling season. Peak demand represents the highest demand on a given day and at a given hour. During 2024, 2023 and 2022, MidAmerican Energy's hourly peak demand was 5,623, 5,851 and 5,386 MWs, respectively. On August 23, 2023, retail customer usage of electricity caused a new record hourly peak demand of 5,851 MWs on MidAmerican Energy's electric distribution system.

Generating Facilities and Fuel Supply

MidAmerican Energy has ownership interests in a diverse portfolio of generating facilities. The following table presents certain information regarding MidAmerican Energy's owned generating facilities as of December 31, 2024:

Generating Facility	Location	Energy Source	Year Installed / Repowered ⁽¹⁾	Facility Net Capacity (MWs) ⁽²⁾	Net Owned Capacity (MWs) ⁽²⁾
WIND:					
Ida Grove	Ida Grove, IA	Wind	2016-2019	500	500
Orient	Greenfield, IA	Wind	2018-2019	500	500
Highland	Primghar, IA	Wind	2015	500	500
Rolling Hills	Massena, IA	Wind	2011 / 2022	443	443
Beaver Creek	Ogden, IA	Wind	2017-2018	340	340
North English	Montezuma, IA	Wind	2018-2019	340	340
Palo Alto	Palo Alto, IA	Wind	2019-2020	340	340

Generating Facility	Location	Energy Source	Year Installed / Repowered ⁽¹⁾	Facility Net Capacity (MWs) ⁽²⁾	Net Owned Capacity (MWs) ⁽²⁾
Arbor Hill	Greenfield, IA	Wind	2018-2020	316	316
Pomeroy	Pomeroy, IA	Wind	2007-2011 / 2018-2019, 2021	286	286
Diamond Trail	Ladora, IA	Wind	2020	250	250
Lundgren	Otho, IA	Wind	2014	250	250
O'Brien	Primghar, IA	Wind	2016	250	250
Southern Hills	Orient, IA	Wind	2020-2021	250	250
Chickasaw	New Hampton, IA	Wind	2023	200	200
Century	Blairsburg, IA	Wind	2005-2008 / 2017-2018 / 2024	200	200
Eclipse	Adair, IA	Wind	2012 / 2022	200	200
Plymouth	Remsen, IA	Wind	2021	200	200
Intrepid	Schaller, IA	Wind	2004-2005 / 2017	176	176
Adair	Adair, IA	Wind	2008 / 2019-2020	175	175
Prairie	Montezuma, IA	Wind	2017-2018	169	169
Carroll	Carroll, IA	Wind	2008 / 2019	150	150
Walnut	Walnut, IA	Wind	2008 / 2019	150	150
Vienna	Gladbrook, IA	Wind	2012-2013 / 2024	150	150
Adams	Lennox, IA	Wind	2015	150	150
Wellsburg	Wellsburg, IA	Wind	2014	139	139
Laurel	Laurel, IA	Wind	2011 / 2022	120	120
Macksburg	Macksburg, IA	Wind	2014	119	119
Contrail	Braddyville, IA	Wind	2020	110	110
Morning Light	Adair, IA	Wind	2012 / 2022-2023	100	100
Victory	Westside, IA	Wind	2006 / 2017-2018	99	99
Ivester	Wellsburg, IA	Wind	2018	90	90
Pocahontas Prairie	Pomeroy, IA	Wind	2020 / 2021	80	80
Charles City	Charles City, IA	Wind	2008 / 2018	75	75
				7,417	7,417
COAL:					
Louisa No. 1	Muscatine, IA	Coal	1983	742	653
Walter Scott, Jr. No. 3	Council Bluffs, IA	Coal	1978	704	557
Walter Scott, Jr. No. 4	Council Bluffs, IA	Coal	2007	809	483
Ottumwa No. 1	Ottumwa, IA	Coal	1981	705	367
George Neal No. 3	Sergeant Bluff, IA	Coal	1975	501	360
George Neal No. 4	Salix, IA	Coal	1979	650	264
				4,111	2,684
NATURAL GAS AND OTHER:					
Greater Des Moines	Pleasant Hill, IA	Gas	2003-2004	504	504
Electrifarm	Waterloo, IA	Gas or Oil	1975-1978	190	190
Pleasant Hill	Pleasant Hill, IA	Gas or Oil	1990-1994	154	154
Sycamore	Johnston, IA	Gas or Oil	1974	141	141
River Hills	Des Moines, IA	Gas	1966-1967	113	113
Coralville	Coralville, IA	Gas	1970	63	63
Moline	Moline, IL	Gas	1970	61	61
27 portable power modules	Various	Oil	2000	54	54
Parr	Charles City, IA	Gas	1969	32	32
				1,312	1,312
NUCLEAR:					
Quad Cities Nos. 1 and 2	Cordova, IL	Uranium	1972	1,811	452
SOLAR:					
Holiday Creek	Fort Dodge, IA	Solar	2022	100	100

Generating Facility	Location	Energy Source	Year Installed / Repowered ⁽¹⁾	Facility Net Capacity (MWs) ⁽²⁾	Net Owned Capacity (MWs) ⁽²⁾
Arbor Hill	Adair, IA	Solar	2022	24	24
Franklin	Hampton, IA	Solar	2022	7	7
Neal	Salix, IA	Solar	2022	4	4
Waterloo	Waterloo, IA	Solar	2022	3	3
Hills	Hills, IA	Solar	2022	3	3
				141	141
HYDROELECTRIC:					
Moline Unit Nos. 1-4	Moline, IL	Hydroelectric	1941	4	4
Total Available Generating Capacity				14,796	12,010

- (1) Repowered dates are associated with component replacements on existing wind-powered generating facilities commonly referred to by the IRS as repowering. IRS rules provide for re-establishment of the PTCs for an existing wind-powered generating facility upon the replacement of a significant portion of its components. If the degree of component replacement in such projects meets IRS guidelines, PTCs are re-established for 10 years beginning with the date the repowered facility is placed in-service.
- (2) Facility Net Capacity represents the lesser of nominal ratings or any limitations under applicable interconnection, power purchase, or other agreements for intermittent resources and the total net dependable capability available during summer conditions for all other units. An intermittent resource's nominal rating is the manufacturer's contractually specified capability (in MWs) under specified conditions. Net Owned Capacity indicates MidAmerican Energy's ownership of Facility Net Capacity.

The following table shows the percentages of MidAmerican Energy's total energy supplied by energy source for the years ended December 31:

	2024	2023	2022
Wind, solar and hydroelectric ⁽¹⁾	59 %	55 %	58 %
Coal	19	22	21
Nuclear	9	8	8
Natural gas	5	5	3
Total energy generated	92	90	90
Energy purchased - short-term contracts and other	7	9	9
Energy purchased - long-term contracts (renewable) ⁽¹⁾	1	1	1
	100 %	100 %	100 %

- (1) All or some of the renewable energy attributes associated with generation from these sources may be: (a) used in future years to comply with RPS or other regulatory requirements, (b) sold to third parties in the form of RECs or other environmental commodities, or (c) excluded from energy purchased.

MidAmerican Energy is required to have accredited resources available for dispatch by MISO to continuously meet its customer's needs and reliably operate its electric system. The percentage of MidAmerican Energy's energy supplied by energy source varies from year to year and is subject to numerous operational and economic factors such as planned and unplanned outages; fuel commodity prices; fuel availability; fuel transportation costs; weather, including temperature, wind and sun; legislative and environmental considerations; transmission constraints; wholesale market prices of electricity and other factors. MidAmerican Energy evaluates these factors continuously in order to facilitate dispatch of its generating facilities by MISO. When factors for one energy source are less favorable, MidAmerican Energy places more reliance on other energy sources. For example, MidAmerican Energy can generate more electricity using its low cost wind-powered generating facilities when factors associated with these facilities are favorable. When factors associated with wind resources are less favorable, MidAmerican Energy must increase its reliance on more expensive generation or purchased electricity. Refer to "General Regulation" in Item 1 of this Form 10-K for a discussion of energy cost recovery by jurisdiction.

Wind

MidAmerican Energy owns more wind-powered generating capacity than any other U.S. rate-regulated electric utility and believes wind-powered generation offers a viable, economical and environmentally prudent means of supplying electricity and complying with laws and regulations. Pursuant to ratemaking principles approved by the IUC, facilities accounting for 89% of MidAmerican Energy's wind-powered generating capacity in-service at December 31, 2024, are authorized to earn a fixed rate of return on equity over their regulatory lives ranging from 10.75% to 12.2% on the depreciated cost of their original construction, which excludes the cost of later replacements, in any future Iowa rate proceeding. MidAmerican Energy's wind-powered generating facilities, including those facilities where a significant portion of the equipment was replaced, commonly referred to as repowered facilities, are eligible for federal renewable electricity PTCs for 10 years beginning with the date the facilities are placed in-service. PTCs are earned as energy from qualifying wind-powered generating facilities is produced and sold. PTCs for MidAmerican Energy's wind-powered generating facilities currently in-service began expiring in 2014, with final expiration in 2033. Since 2014, MidAmerican Energy has repowered 2,490 MWs of wind-powered generating facilities for which PTCs had expired and plans to repower 1,486 MWs of wind-powered generating facilities for which PTCs will expire from 2025-2027.

Of the 7,616 MWs (nameplate capacity) of wind-powered generating facilities in-service, 7,562 MWs were generating PTCs at some point in 2024, including 2,490 MWs of repowered facilities. PTCs earned by MidAmerican Energy's wind-powered generating facilities placed in-service prior to 2013, except for repowered facilities, were included in MidAmerican Energy's Iowa EAC, through which MidAmerican Energy is allowed to recover fluctuations in its electric retail energy costs. All of the eligibility of those facilities to earn PTCs had expired by the end of 2022. MidAmerican Energy earned PTCs from wind-powered generating facilities totaling \$761 million, \$681 million and \$710 million in 2024, 2023 and 2022, respectively, of which —%, —% and 4%, respectively, were included in the Iowa EAC.

Coal

All the coal-fueled generating facilities operated by MidAmerican Energy are fueled by low-sulfur, sub-bituminous coal from the Powder River Basin in northeast Wyoming. MidAmerican Energy's coal supply portfolio includes multiple suppliers and mines under short-term and multi-year agreements of varying terms and quantities through 2027. MidAmerican Energy believes supplies from these sources are presently adequate and available to meet MidAmerican Energy's needs. Essentially all of MidAmerican Energy's expected coal supply requirements are covered under fixed-price contracts. MidAmerican Energy regularly monitors the western coal market for opportunities to enhance its coal supply portfolio.

MidAmerican Energy has a multi-year long-haul coal transportation agreement with BNSF Railway Company ("BNSF"), an affiliate company, for the delivery of coal to two MidAmerican Energy-operated coal-fueled generating facilities. Under this agreement, BNSF delivers coal directly to MidAmerican Energy's Walter Scott, Jr. Energy Center and to an interchange point with Canadian Pacific Kansas City Railway Company ("CPKC"). MidAmerican Energy has a single-year contract for short-haul delivery with CPKC from the interchange point to the Louisa Energy Center. MidAmerican Energy has a multi-year long-haul coal transportation agreement with Union Pacific Railroad Company for the delivery of coal to the George Neal Energy Center.

Nuclear

MidAmerican Energy is a 25% joint owner of Quad Cities Generating Station Units 1 and 2 ("Quad Cities Station"), a nuclear generating facility, which is currently licensed by the NRC for operation until December 14, 2032. Constellation Energy Generation, LLC ("Constellation Energy"), is the 75% joint owner and the operator of Quad Cities Station. Approximately one-third of the nuclear fuel assemblies in each reactor core at Quad Cities Station is replaced every 24 months. MidAmerican Energy has been advised by Constellation Energy that it expects to obtain the necessary uranium concentrates, conversion, enrichment and fabrication services to meet the nuclear fuel requirements of Quad Cities Station. In reaction to concerns about the profitability of Quad Cities Station and Constellation Energy's ability to continue its operation, in December 2016, Illinois passed legislation creating a zero-emission standard, which went into effect June 1, 2017. The zero-emission standard requires the Illinois Power Agency to purchase ZECs and recover the costs from certain ratepayers in Illinois, subject to certain limitations. Currently, Quad Cities is operating under agreements to provide Illinois load serving entities ZECs through May 31, 2027. Additionally, on August 16, 2022, the Inflation Reduction Act of 2022 was signed into law which contained numerous provisions, including expanded tax credits for clean energy incentives. As a result of the enactment of the Inflation Reduction Act of 2022, MidAmerican Energy's ownership of the Quad Cities Station qualifies for federal nuclear PTCs which provide a tax credit beginning in 2024 for qualifying production volumes subject to a phase-out based on annual gross receipts. Both the amount of the PTC and the gross receipt thresholds adjust annually for inflation over the duration of the program. MidAmerican Energy earned nuclear PTCs totaling \$49 million in 2024, of which 88% was included in the Iowa EAC.

Natural Gas and Other

MidAmerican Energy uses natural gas and oil as fuel for intermediate and peak demand electric generation, igniter fuel, transmission support and standby purposes. These sources are presently in adequate supply and available to meet MidAmerican Energy's needs.

Regional Transmission Organizations

MidAmerican Energy sells and purchases electricity and ancillary services related to its generation and load in wholesale markets pursuant to the tariffs in those markets. MidAmerican Energy participates predominantly in the MISO energy and ancillary service markets, which provide MidAmerican Energy with wholesale opportunities over a large market area. MidAmerican Energy can enter into wholesale bilateral transactions in addition to market activity related to its assets. MidAmerican Energy is also authorized to participate in the Southwest Power Pool, Inc. and PJM Interconnection, L.L.C. ("PJM") markets and can contract with several other utilities in the region.

The MISO requires each member to maintain a minimum seasonal reserve margin of its accredited generating capacity over its seasonal peak demand obligation based on the member's seasonal load forecast filed with the MISO each year. Owned and contracted accredited capacity represents the amount of generation available to meet the requirements of MidAmerican Energy's retail customers and consists of MidAmerican Energy-owned generation, interruptible retail customer load, certain customer private generation that MidAmerican Energy is contractually allowed to dispatch and the net amount of capacity purchases and sales, excluding sales into the MISO annual capacity auction. Accredited capacity may vary significantly from the nominal capacity ratings, particularly for wind or solar facilities whose output is dependent upon energy resource availability at any given time. Additionally, the actual amount of generating capacity available at any time may be less than the accredited capacity due to regulatory restrictions, transmission constraints, fuel restrictions and generating units being temporarily out of service for inspection, maintenance, refueling, modifications or other reasons. The MISO's reserve requirements for the 2024-2025 planning year were 9.0% for summer 2024, 14.2% for fall 2024, 27.4% for winter 2024-2025 and 26.7% for spring 2025. For the summer peak demand season, MidAmerican Energy's owned and contracted capacity accredited for the 2024-2025 MISO capacity auction was 5,932 MWs compared to a peak demand obligation of 5,469 MWs. MidAmerican Energy purchased an additional 28 MWs in the MISO Planning Resource Auction for a total capacity of 5,961 MWs to fulfill the MISO summer reserve requirements. MidAmerican Energy has more than adequate reserve margin for the fall, winter and spring peak demand seasons. Some of the excess capacity may be sold through bilateral or MISO capacity auction transactions. The reserve requirements for the 2025-2026 planning year will be 7.9% for summer 2025, 14.9% for fall 2025, 18.4% for winter 2025-2026 and 25.3% for spring 2026. MidAmerican Energy's decisions regarding additions to or reductions of its generation portfolio may be impacted by the MISO's minimum reserve margin requirements.

Transmission and Distribution

MidAmerican Energy's transmission and distribution systems included 4,700 circuit miles of transmission lines in four states, 25,700 circuit miles of distribution lines and 340 substations as of December 31, 2024. Electricity from MidAmerican Energy's generating facilities and purchased electricity is delivered to wholesale markets and its retail customers via the transmission facilities of MidAmerican Energy and others. MidAmerican Energy participates in the MISO capacity, energy and ancillary services markets as a transmission-owning member and, accordingly, operates its transmission assets at the direction of the MISO. The MISO manages its energy and ancillary service markets using reliability-constrained dispatch of the region's generation. For both the day-ahead and real-time (every five minutes) markets, the MISO analyzes generation commitments to provide market liquidity and transparent pricing while maintaining transmission system reliability by minimizing congestion and maximizing efficient energy transmission. Additionally, through its FERC-approved OATT, the MISO performs the role of transmission service provider throughout the MISO footprint and administers the long-term planning function. The MISO costs of the participants are shared among the participants through a number of mechanisms in accordance with the MISO tariff.

Regulated Natural Gas Operations

MidAmerican Energy is engaged in the distribution of natural gas to customers in its service territory and the related procurement, transportation and storage of natural gas for the benefit of those customers. MidAmerican Energy purchases natural gas from various suppliers and contracts with interstate natural gas pipelines for transportation of the gas to MidAmerican Energy's service territory and for storage and balancing services. MidAmerican Energy sells natural gas and delivery services to end-use customers on its distribution system; sells natural gas to other utilities, municipalities and energy marketing companies; and transports natural gas through its distribution system for end-use customers who have independently secured their supply of natural gas. During 2024, 60% of the total natural gas delivered through MidAmerican Energy's distribution system was associated with transportation service.

Natural gas property consists primarily of natural gas mains and service lines, meters, and related distribution equipment, including feeder lines to communities served from natural gas pipelines owned by others. The natural gas distribution facilities of MidAmerican Energy included 25,000 miles of natural gas main and service lines as of December 31, 2024.

Customer Usage and Seasonality

The percentages of natural gas sold to MidAmerican Energy's retail customers by jurisdiction for the years ended December 31 were as follows:

	2024	2023	2022
Iowa	75 %	75 %	76 %
South Dakota	14	14	14
Illinois	10	10	9
Nebraska	1	1	1
	<u>100 %</u>	<u>100 %</u>	<u>100 %</u>

The percentages of natural gas sold to MidAmerican Energy's retail and wholesale customers by class of customer, total Dths of natural gas sold, total Dths of transportation service and the average number of retail customers for the years ended December 31 were as follows:

	2024	2023	2022
Dths sold:			
Residential	44 %	45 %	47 %
Commercial ⁽¹⁾	21	21	22
Industrial ⁽¹⁾	5	5	5
Total retail	70	71	74
Wholesale ⁽²⁾	30	29	26
	<u>100 %</u>	<u>100 %</u>	<u>100 %</u>
Dths of natural gas sold (in thousands):	<u>102,186</u>	<u>106,912</u>	<u>119,508</u>
Dths of transportation service (in thousands):	<u>108,667</u>	<u>106,422</u>	<u>102,827</u>
Average number of retail customers (in thousands):			
Residential	729	723	716
Commercial	70	69	69
Industrial	1	1	1
Other	3	3	3
Total	<u>803</u>	<u>796</u>	<u>789</u>

(1) Commercial and industrial customers are classified primarily based on the nature of their business and natural gas usage. Commercial customers are non-residential customers that use natural gas principally for heating. Industrial customers are non-residential customers that use natural gas principally for their manufacturing processes.

(2) Wholesale sales are generally made to other utilities, municipalities and energy marketing companies for eventual resale to end-use customers.

There are seasonal variations in MidAmerican Energy's regulated natural gas business that are principally due to the use of natural gas for heating. Typically, 50-60% of MidAmerican Energy's regulated retail natural gas revenue is reported in the months of January, February, March and December.

During 2024, 2023 and 2022, MidAmerican Energy's peak-day delivery through its distribution system was 1,309,874, 1,119,503 and 1,325,160 Dths, respectively. On January 20, 2025, MidAmerican Energy recorded its all-time highest peak-day of 1,372,402 Dths. This preliminary peak-day delivery consisted of 66% traditional retail sales service and 34% transportation service.

Natural Gas Supply and Capacity

MidAmerican Energy uses several strategies designed to maintain a reliable natural gas supply and reduce the impact of volatility in natural gas prices on its regulated retail natural gas customers. These strategies include the purchase of a geographically diverse supply portfolio from producers and third-party energy marketing companies, the use of interstate pipeline storage services and MidAmerican Energy's LNG peaking facilities, and the use of financial derivatives to fix the price on a portion of the anticipated natural gas requirements of MidAmerican Energy's customers. Refer to "General Regulation" in Item 1 of this Form 10-K for a discussion of the PGAs.

MidAmerican Energy contracts for firm natural gas pipeline capacity to transport natural gas from key production areas and liquid market centers to its service territory through direct interconnects to the pipeline systems of several interstate natural gas pipeline systems, including Northern Natural Gas, an affiliate company. MidAmerican Energy has multiple pipeline interconnections into several larger markets within its distribution system. Multiple pipeline interconnections create competition among pipeline suppliers for transportation capacity to serve those markets, thus reducing costs. In addition, multiple pipeline interconnections increase delivery reliability and give MidAmerican Energy the ability to optimize delivery of the lowest cost supply from the various production areas and liquid market centers into these markets. Benefits to MidAmerican Energy's distribution system customers are shared among all jurisdictions through a consolidated PGA.

At times, the natural gas pipeline capacity available through MidAmerican Energy's firm capacity portfolio may exceed the requirements of retail customers on MidAmerican Energy's distribution system. Firm capacity in excess of MidAmerican Energy's system needs can be released to other companies to achieve optimum use of the available capacity. Past IUC and South Dakota Public Utilities Commission ("SDPUC") rulings have allowed MidAmerican Energy to retain 30% of the revenue on the resold capacity, with the remaining 70% being returned to customers through the PGAs.

MidAmerican Energy utilizes interstate pipeline natural gas storage services to meet retail customer requirements, manage fluctuations in demand due to changes in weather and other usage factors and manage variation in seasonal natural gas pricing. MidAmerican Energy typically withdraws natural gas from storage during the heating season when customer demand is historically at its peak and injects natural gas into storage during off-peak months when customer demand is historically lower. MidAmerican Energy also utilizes its three LNG facilities to meet peak day demands during the winter heating season. Interstate pipeline storage services and MidAmerican Energy's LNG facilities reduce dependence on natural gas purchases during the volatile winter heating season and can deliver a significant portion of MidAmerican Energy's anticipated retail sales requirements on a peak winter day. For MidAmerican Energy's 2024/2025 winter heating season preliminary peak-day of January 20, 2025, supply sources used to meet deliveries to traditional retail sales service customers included 50% from purchases delivered on interstate pipelines, 37% from interstate pipeline storage services and 13% from MidAmerican Energy's LNG facilities.

MidAmerican Energy attempts to optimize the value of its regulated transportation capacity, natural gas supply and interstate pipeline storage services by engaging in wholesale transactions. IUC and SDPUC rulings have allowed MidAmerican Energy to retain 50% of the respective jurisdictional margins earned on certain wholesale sales of natural gas, with the remaining 50% being returned to customers through the PGAs.

MidAmerican Energy is not aware of any factors that would cause material difficulties in meeting its anticipated retail customer demand under normal operating conditions for the foreseeable future.

Energy Efficiency Programs

MidAmerican Energy has provided a comprehensive set of DSM programs to its Iowa electric and natural gas customers since 1990. The programs, collectively referred to as energy efficiency programs, are designed to reduce energy consumption and more effectively manage when energy is used, including management of seasonal peak loads. Current programs offer services to customers such as energy engineering audits and information on how to improve the efficiency of their homes and businesses. To assist customers in investing in energy efficiency, MidAmerican Energy offers rebates or incentives encouraging the purchase and installation of high-efficiency equipment such as lighting, heating and cooling equipment, weatherization, motors, process equipment and systems, as well as incentives for efficient construction. Incentives are also paid to residential customers who participate in the air conditioner load control program and nonresidential customers who participate in the nonresidential load management program. In Iowa, legislation passed in 2018 provides that projected cumulative average annual costs for a natural gas energy efficiency plan cannot exceed 1.5% of expected Iowa natural gas retail revenue and, for an electric demand response plan and separately for an electric energy efficiency plan other than demand response, cannot exceed 2.0% of expected annual Iowa electric retail revenue. Although subject to prudence reviews, state regulations allow for contemporaneous recovery of costs incurred for energy efficiency programs through state-specific energy efficiency service charges paid by all retail electric and natural gas customers. In 2024, \$51 million was expensed for MidAmerican Energy's energy efficiency programs, which resulted in estimated first-year energy savings of 163,000 MWhs of electricity and 156,000 Dths of natural gas and an estimated peak load reduction of 322 MWs of electricity and 2,442 Dths per day of natural gas.

Human Capital

Employees

As of December 31, 2024, MidAmerican Funding and MidAmerican Energy had approximately 3,500 employees, of which approximately 1,400 were covered by union contracts. MidAmerican Energy has three separate contracts with locals of the International Brotherhood of Electrical Workers and the United Steel, Paper and Forestry, Rubber, Manufacturing, Energy, Allied Industrial and Service Workers International Union. A contract with the International Brotherhood of Electrical Workers covering substantially all of the union employees expires April 30, 2027. For more information regarding MidAmerican Funding's and MidAmerican Energy's human capital disclosures, refer to Item 1. Business - General section of this Form 10-K.

NV ENERGY (NEVADA POWER AND SIERRA PACIFIC)

General

NV Energy, an indirect wholly owned subsidiary of BHE, is an energy holding company headquartered in Nevada whose principal subsidiaries are Nevada Power and Sierra Pacific. Nevada Power and Sierra Pacific are indirect consolidated subsidiaries of Berkshire Hathaway. Nevada Power is a U.S. regulated electric utility company serving 1.0 million retail customers primarily in the Las Vegas, North Las Vegas, Henderson and adjoining areas. Sierra Pacific is a U.S. regulated electric and natural gas utility company serving 0.4 million retail electric customers and 0.2 million retail and transportation natural gas customers in northern Nevada. The Nevada Utilities are principally engaged in the business of generating, transmitting, distributing and selling electricity and, in the case of Sierra Pacific, in distributing, selling and transporting natural gas. Nevada Power and Sierra Pacific have electric service territories covering approximately 4,500 square miles and 41,400 square miles, respectively. Sierra Pacific has a natural gas service territory covering approximately 900 square miles in Reno and Sparks. Principal industries served by the Nevada Utilities include gaming, recreation, warehousing, manufacturing and governmental services. Sierra Pacific also serves the mining industry. The Nevada Utilities buy and sell electricity on the wholesale market with other utilities, energy marketing companies, financial institutions and other market participants to balance and optimize economic benefits of electricity generation, retail customer loads and wholesale transactions.

The Nevada Utilities' electric and natural gas operations are conducted under numerous nonexclusive franchise agreements, revocable permits and licenses obtained from federal, state and local authorities. The franchise agreements, with various expiration dates, are typically for 10- to 20-year terms. The Nevada Utilities operate under certificates of public convenience and necessity as regulated by the PUCN, and as such the Nevada Utilities have an obligation to provide electricity service to those customers within their service territory. In return, the PUCN has established rates on a cost-of-service basis, which are designed to allow the Nevada Utilities an opportunity to recover all prudently incurred costs of providing services and an opportunity to earn a reasonable return on their investment.

NV Energy's monthly net income is affected by the seasonal impact of weather on electricity and natural gas sales and seasonal retail electricity prices from the Nevada Utilities'. For 2024, 78% of NV Energy annual net income was recorded in the months of June through September.

Regulated electric utility operations is Nevada Power's only segment while regulated electric utility operations and regulated natural gas operations are the two segments of Sierra Pacific.

Sierra Pacific's operating revenue and operating income derived from the following business activities for the years ended December 31 were as follows (dollars in millions):

	2024		2023		2022	
Operating revenue:						
Electric	\$ 1,080	86 %	\$ 1,194	83 %	\$ 1,025	86 %
Gas	182	14	237	17	168	14
Total operating revenue	<u>\$ 1,262</u>	<u>100 %</u>	<u>\$ 1,431</u>	<u>100 %</u>	<u>\$ 1,193</u>	<u>100 %</u>
Operating income:						
Electric	\$ 122	94 %	\$ 133	88 %	\$ 146	88 %
Gas	8	6	19	12	19	12
Total operating income	<u>\$ 130</u>	<u>100 %</u>	<u>\$ 152</u>	<u>100 %</u>	<u>\$ 165</u>	<u>100 %</u>

Nevada Power was incorporated under the laws of the state of Nevada in 1929 and its principal executive offices are located at 6226 West Sahara Avenue, Las Vegas, Nevada 89146, its telephone number is (702) 402-5000 and its internet address is www.nvenergy.com.

Sierra Pacific was incorporated under the laws of the state of Nevada in 1912 and its principal executive offices are located at 6100 Neil Road, Reno, Nevada 89511, its telephone number is (775) 834-4011 and its internet address is www.nvenergy.com.

Regulated Electric Operations

Customers

The Nevada Utilities' sell electricity to retail customers in a single state jurisdiction. Electricity sold to the Nevada Utilities' retail and wholesale customers by class of customer and the average number of retail customers for the years ended December 31 were as follows:

	2024		2023		2022	
<u>Nevada Power:</u>						
GWhs sold:						
Residential	10,535	41 %	9,584	41 %	10,299	42 %
Commercial	5,045	20	4,807	20	4,904	21
Industrial	6,356	25	5,827	25	5,630	23
Other	179	1	179	1	191	1
Total fully bundled	22,115	87	20,397	87	21,024	87
Distribution only service	2,918	11	2,831	12	2,786	11
Total retail	25,033	98	23,228	99	23,810	98
Wholesale	465	2	230	1	586	2
Total GWhs sold	<u>25,498</u>	<u>100 %</u>	<u>23,458</u>	<u>100 %</u>	<u>24,396</u>	<u>100 %</u>
Average number of retail customers (in thousands):						
Residential	916	89 %	899	89 %	886	89 %
Commercial	117	11	114	11	113	11
Industrial	2	—	2	—	2	—
Total	<u>1,035</u>	<u>100 %</u>	<u>1,015</u>	<u>100 %</u>	<u>1,001</u>	<u>100 %</u>
<u>Sierra Pacific:</u>						
GWhs sold:						
Residential	2,726	22 %	2,655	23 %	2,747	22 %
Commercial	3,108	25	2,998	25	3,124	26
Industrial	2,811	23	2,684	23	2,867	23
Other	9	—	11	—	13	—
Total fully bundled	8,654	70	8,348	71	8,751	71
Distribution only service	2,958	24	2,829	24	2,757	23
Total retail	11,612	94	11,177	95	11,508	94
Wholesale	683	6	621	5	741	6
Total GWhs sold	<u>12,295</u>	<u>100 %</u>	<u>11,798</u>	<u>100 %</u>	<u>12,249</u>	<u>100 %</u>
Average number of retail customers (in thousands):						
Residential	331	87 %	326	87 %	322	87 %
Commercial	51	13	50	13	49	13
Total	<u>382</u>	<u>100 %</u>	<u>376</u>	<u>100 %</u>	<u>371</u>	<u>100 %</u>

Variations in weather, economic conditions, particularly for gaming, mining and wholesale customers and various conservation, energy efficiency and private generation measures and programs can impact customer energy requirements. Wholesale sales are impacted by market prices for energy relative to the incremental cost to generate power.

There are seasonal variations in the Nevada Utilities' electric business that are principally related to weather and the related use of electricity for air conditioning. Typically, 47-52% of Nevada Power's and 37-40% of Sierra Pacific's regulated electric revenue is reported in the months of June through September.

The annual hourly peak customer demand on the Nevada Utilities' electric systems occurs as a result of air conditioning use during the cooling season. Peak demand represents the highest demand on a given day and at a given hour. During the summer months of 2024, 2023 and 2022, customer usage of electricity caused an hourly peak demand on Nevada Power's electric system of 6,656, 6,311 and 6,033 MWs, respectively, and on Sierra Pacific's electric system of 2,113, 1,825 and 1,962 MWs, respectively.

Generating Facilities and Fuel Supply

The Nevada Utilities have ownership interests in a diverse portfolio of generating facilities. The following table presents certain information regarding the Nevada Utilities' owned generating facilities as of December 31, 2024:

Generating Facility	Location	Energy Source	Installed	Facility Net Capacity (MWs) ⁽¹⁾	Net Owned Capacity (MWs) ⁽¹⁾
Nevada Power:					
NATURAL GAS:					
Lenzie	Las Vegas, NV	Natural gas	2006	1,218	1,218
Clark	Las Vegas, NV	Natural gas	1973-2008	1,144	1,144
Silverhawk ⁽²⁾	Las Vegas, NV	Natural gas	2004-2024	1,034	1,034
Harry Allen	Las Vegas, NV	Natural gas	1995-2011	680	680
Higgins	Primm, NV	Natural gas	2004	602	602
Las Vegas	Las Vegas, NV	Natural gas	1994-2003	272	272
Sun Peak	Las Vegas, NV	Natural gas/oil	1991	210	210
				<u>5,160</u>	<u>5,160</u>
RENEWABLES:					
Dry Lake	Dry Lake, NV	Solar	2024	150	150
Nellis	Las Vegas, NV	Solar	2015	15	15
Goodsprings	Goodsprings, NV	Waste heat	2010	5	5
				<u>170</u>	<u>170</u>
Total Nevada Power Available Generating Capacity				<u>5,330</u>	<u>5,330</u>
Sierra Pacific:					
NATURAL GAS:					
Tracy	Sparks, NV	Natural gas	1974-2008	763	763
Ft. Churchill	Yerington, NV	Natural gas	1968-1971	196	196
Clark Mountain	Sparks, NV	Natural gas	1994	128	128
				<u>1,087</u>	<u>1,087</u>
COAL:					
Valmy Unit Nos. 1 and 2	Valmy, NV	Coal	1981-1985	522	261
RENEWABLES:					
Ft. Churchill	Yerington, NV	Solar	2015	20	20
Total Sierra Pacific Available Generating Capacity				<u>1,629</u>	<u>1,368</u>
Total NV Energy Available Generating Capacity				<u>6,959</u>	<u>6,698</u>
PROJECTS UNDER CONSTRUCTION:					
Sierra Solar ⁽³⁾	Fernley, NV	Solar	Est. 2027	400	400
				<u>7,359</u>	<u>7,098</u>

(1) Facility Net Capacity represents the lesser of nominal ratings or any limitations under applicable interconnection, power purchase, or other agreements for intermittent resources and the total net dependable capability available during summer conditions for all other units. An intermittent resource's nominal rating is the manufacturer's contractually specified capability (in MWs) under specified conditions. Net Owned Capacity indicates Nevada Power or Sierra Pacific's ownership of Facility Net Capacity.

(2) Additional generating units at the Silverhawk generating facility in Clark County, Nevada were placed into commercial operation in July 2024 creating an additional 444 MW of peaking combustion turbines.

- (3) In addition to the 400 MW solar photovoltaic facility, Sierra Solar has 400 MW of co-located battery energy storage that will be developed in Fernley, Nevada with commercial operation expected by 2026. The solar photovoltaic portion is expected to be operational in 2027. The facility ownership share is allocated 90% to Sierra Pacific and 10% to Nevada Power Company.

In December 2023, Nevada Power put into service its Reid Gardner battery energy storage system located in Moapa, Nevada, having total Facility Net Capacity and Net Owned Capacity of 220 MWs.

In May 2024, Nevada Power put into service its Dry Lake photovoltaic facility with a co-located battery energy storage system located in Dry Lake, Nevada, having total Facility Net Capacity and Net Owned Capacity of 150 MWs for the photovoltaic facility and 100 MWs of co-located battery storage.

The Nevada Utilities have entered into multiple long-term electricity contracts that it considers part of the total available generating capacity. The following table presents facility net capacity regarding generation sources of the Nevada Utilities' long-term purchased electricity contracts as of December 31, 2024:

Electricity Contract Energy Source	Capacity MWs
Solar	2,851
Geothermal	403
Hydroelectric	250
Wind	152
Other renewable	15
Total renewable	3,671
Other	11
Total contract capacity	3,682

The following table shows the percentages of the Nevada Utilities' total energy supplied by energy source for the years ended December 31:

	2024	2023	2022
Nevada Power:			
Natural gas	65 %	65 %	60 %
Renewable ⁽¹⁾	2	—	—
Total energy generated	67	65	60
Energy purchased - long-term contracts (renewable) ⁽²⁾	29	24	23
Energy purchased - long-term contracts (non-renewable)	1	5	9
Energy purchased - short-term contracts and other	3	6	8
	100 %	100 %	100 %
Sierra Pacific:			
Natural gas	49 %	44 %	41 %
Coal	10	8	11
Total energy generated ⁽¹⁾	59	52	52
Energy purchased - long-term contracts (renewable) ⁽²⁾	35	32	28
Energy purchased - long-term contracts (non-renewable)	4	9	11
Energy purchased - short-term contracts and other	2	7	9
	100 %	100 %	100 %

(1) Energy generated from renewable generating facilities mainly comprises of the solar resources related to the Dry Lake solar generating facility that was placed into service in May 2024.

(2) All or some of the renewable energy attributes associated with generation from these sources may be: (a) used in future years to comply with RPS or other regulatory requirements, (b) sold to third parties in the form of RECs or other environmental commodities, or (c) excluded from energy purchased.

The Nevada Utilities are required to have resources available to continuously meet their customer needs and reliably operate their electric systems. The percentage of the Nevada Utilities' energy supplied by energy source varies from year-to-year and is subject to numerous operational and economic factors such as planned and unplanned outages; fuel commodity prices; fuel availability; fuel transportation costs; weather, including temperature, wind and sun; legislative and environmental considerations; transmission constraints; wholesale market prices of electricity and other factors. The Nevada Utilities evaluate these factors continuously in order to facilitate dispatch of their generating facilities. When factors for one energy source are less favorable, the Nevada Utilities place more reliance on other energy sources. As long as the Nevada Utilities' purchases are deemed prudent by the PUCN, through their annual prudency review, the Nevada Utilities are permitted to recover the cost of fuel and purchased power. The Nevada Utilities also have the ability to reset quarterly the BTERs, with PUCN approval, based on the last 12 months fuel costs and purchased power and to reset the quarterly DEAA.

The Nevada Utilities have adopted an approach to managing the energy supply function that has three primary elements. The first element is a set of management guidelines for procuring and optimizing the supply portfolio that is consistent with the requirements of a load serving entity with a full requirements obligation, and with the growth of private generation serving a small but growing group of customers with partial requirements. The second element is an energy risk management and control approach that ensures clear separation of roles between the day-to-day management of risks and compliance monitoring and control and ensures clear distinction between planning and execution. Lastly, the Nevada Utilities pursue a process of ongoing regulatory involvement and acknowledgment of the resource portfolio management plans.

The Nevada Utilities have entered into multiple long-term power purchase contracts (three or more years) with suppliers that generate electricity utilizing renewable resources and natural gas. Nevada Power has entered into contracts with a total capacity of 3,752 MWs with contract termination dates ranging from 2025 to 2067. Included in these contracts are 3,752 MWs of capacity from renewable energy, of which 1,028 MWs of capacity are under development or construction and not currently available. Sierra Pacific has entered into contracts with a total capacity of 1,193 MWs with contract termination dates ranging from 2025 to 2053. Included in these contracts are 1,181 MWs of capacity from renewable energy, of which 235 MWs of capacity are under development or construction and not currently available.

The Nevada Utilities manage certain risks relating to their supply of electricity and fuel requirements by entering into various contracts, which may be accounted for as derivatives, including forwards, futures, options, swaps and other agreements. Refer to NV Energy's "General Regulation" section in Item 1 of this Form 10-K for a discussion of energy cost recovery by jurisdiction and Nevada Power's Item 7A and Sierra Pacific's Item 7A in this Form 10-K for a discussion of commodity price risk and derivative contracts.

Natural Gas

The Nevada Utilities rely on indexed physical gas purchases for the majority of natural gas needed to operate their generating facilities. To secure natural gas supplies for the generating facilities, the Nevada Utilities execute purchases pursuant to a PUCN approved four-season laddering strategy. In 2024, natural gas supply net purchases averaged 332,172 and 153,887 Dths per day with the winter period contracts averaging 301,949 and 183,953 Dths per day and the summer period contracts averaging 353,640 and 132,532 Dths per day for Nevada Power and Sierra Pacific, respectively. The Nevada Utilities believe supplies from these sources are presently adequate and available to meet its needs.

The Nevada Utilities contract for firm natural gas pipeline capacity to transport natural gas from production areas to their service territory through direct interconnects to the pipeline systems of several interstate natural gas pipeline systems, including Nevada Power who contracts with Kern River, an affiliated company. Sierra Pacific utilizes natural gas storage contracted from interstate pipelines to meet retail customer requirements and to manage the daily changes in demand due to changes in weather and other usage factors. The stored natural gas is typically replaced during off-peak months when the demand for natural gas is historically lower than during the heating season.

Coal

Sierra Pacific relies on spot market solicitations for coal supplies and will regularly monitor the western coal market for opportunities to meet these needs. Sierra Pacific has a transportation services contract with Union Pacific Railroad Company to ship coal from various origins in central Utah, western Colorado and Wyoming that expires December 31, 2025. Sierra Pacific has a transportation services contract with BNSF, an affiliate company, to ship coal from western Montana that expires August 31, 2025. The Valmy generating facility, Sierra Pacific's remaining facility requiring coal, has an approved retirement date of December 2025. Sierra Pacific proposed in its Fifth Amendment to the 2021 Joint Integrated Resource Plan to convert the existing coal-fueled plant to a cleaner natural gas-fueled plant which was approved by the PUCN in April 2024 as delineated in the final modified order. Nevada Power has no coal requirements.

Energy Imbalance Market

The Nevada Utilities participate in the EIM operated by the California ISO, which reduces costs to serve customers through more efficient dispatch of a larger and more diverse pool of resources, more effectively integrates renewables and enhances reliability through improved situational awareness and responsiveness. The EIM expands the real-time component of the California ISO's market technology to optimize and balance electricity supply and demand every five minutes across the EIM footprint. The EIM is voluntary and available to all balancing authorities in the western U.S. EIM market participants submit bids to the California ISO market operator before each hour for each generating resource they choose to be dispatched by the market. Each bid is comprised of a dispatchable operating range, ramp rate and prices across the operating range. The California ISO market operator uses sophisticated technology to select the least-cost resources to meet demand and send simultaneous dispatch signals to every participating generator across the EIM footprint every five minutes. In addition to generation resource bids, the California ISO market operator also receives continuous real-time updates of the transmission grid network, meteorological and load forecast information that it uses to optimize dispatch instructions. Outside the EIM footprint, utilities in the western U.S. do not utilize comparable technology and are largely limited to transactions within the borders of their balancing authority area to balance supply and demand intra-hour using a combination of manual and automated dispatch. The EIM delivers customer benefits by leveraging automation and resource diversity to result in more efficient dispatch, more effective integration of renewables and improved situational awareness. Benefits are expected to increase further with renewable resource expansion and as more entities join the EIM bringing incremental diversity.

Transmission and Distribution

The Nevada Utilities' transmission system is part of the Western Interconnection, a regional grid in the U.S. The Western Interconnection includes the interconnected transmission systems of 14 western states, two Canadian provinces and parts of Mexico. The Nevada Utilities' transmission system, together with contractual rights on other transmission systems, enables the Nevada Utilities to integrate and access generation resources to meet their customer load requirements. Nevada Power's transmission and distribution systems included approximately 1,900 miles of transmission lines, 14,500 miles of distribution lines and 220 substations as of December 31, 2024. Sierra Pacific's transmission and distribution systems included approximately 4,200 miles of transmission lines, 9,600 miles of distribution lines and 200 substations as of December 31, 2024.

ON Line is a 231-mile, 500-kV transmission line connecting Nevada Power's and Sierra Pacific's service territories. ON Line provides the ability to jointly dispatch energy throughout Nevada and provide access to renewable energy resources in parts of northern and eastern Nevada, which enhances the Nevada Utilities' ability to manage and optimize their generating facilities. ON Line provides between 600 MWs northbound and 900 MWs southbound of transfer capability with interconnection between the Robinson Summit substation on the Sierra Pacific system and the Harry Allen substation on the Nevada Power system. ON Line was a joint project between the Nevada Utilities and Great Basin Transmission, LLC. The Nevada Utilities own a 25% interest in ON Line and have entered into a long-term transmission use agreement with Great Basin Transmission, LLC for its 75% interest in ON Line until 2054. The Nevada Utilities share of its 25% interest in ON Line and the long-term transmission use agreement is split 75% for Nevada Power and 25% for Sierra Pacific.

The PUCN has approved the Nevada Utilities' Greenlink Nevada transmission expansion program, with an estimated cost of approximately \$4.2 billion, which builds a foundation for the Nevada Utilities to accommodate existing and future transmission network customers, increase transmission system reliability, create access to diversified renewable resources, facilitate development of existing designated solar energy zones, facilitate conventional generation retirement and achieve Nevada's carbon reduction and eventual net-zero objectives. The Greenlink program consists of a 350-mile, 525-kV transmission line, known as Greenlink West, connecting the Ft. Churchill substation, near Yerington, Nevada to the Northwest substation, near Las Vegas, Nevada to the Harry Allen substation, near Las Vegas, Nevada; a 235-mile, 525-kV transmission line, known as Greenlink North, connecting the new Ft. Churchill substation, near Yerington, Nevada to the Robinson Summit substation, near Ely, Nevada; a 46-mile, 345-kV transmission line from the new Ft. Churchill substation, near Yerington, Nevada to the Mira Loma substations, near Yerington, Nevada; and a 38-mile, 345-kV transmission line from the new Ft. Churchill substation, near Yerington, Nevada to the Comstock Meadows substations, near Reno, Nevada. The Greenlink program will be constructed in stages that are estimated to be placed in-service between May 2027 and December 2028. The Nevada Utilities will jointly own and operate the Greenlink transmission lines with Nevada Power having a 70% ownership share in Greenlink West and North and Sierra Pacific having a 30% ownership share. Sierra Pacific will have a 100% ownership share in the Greenlink Common Ties. Through December 31, 2024, \$464 million had been spent.

Natural Disaster Protection Plan

The Nevada Utilities have developed detailed natural disaster protection plans for its service territory and areas in which it owns and operates assets. Natural disaster protection plans are filed annually with the PUCN on or before March 1 of every third year with annual updates to be filed on or before September 1 of the second and third years of the plan. These plans include capital investment in asset hardening and meteorological systems, the implementation of risk modeling tools and the Nevada Utilities' ongoing enhanced safety settings, inspections, vegetation management, enhancement to situational awareness to include implementation of wildfire alert cameras and weather stations in extreme fire-risk areas. In addition, NV Energy has an active power shutoff program referred to as public safety outage management ("PSOM") as well as an emergency de-energization policy in response to active wildfires encroaching the company's infrastructure.

Asset Hardening

The Nevada Utilities have and continue to invest in rebuilding overhead transmission and distribution lines with covered conductor and fire mesh and in some cases have converted overhead distribution lines to underground. These system hardening efforts reduce the exposure of the Nevada Utilities' lines to interference from trees and other objects. Covered conductor helps mitigate the risk of fault-caused electrical arcs that could cause an ignition. Overall, mitigated overhead lines help reduce ignition risk and improve reliability during storms or periods of significant wildfire risk.

The Nevada Utilities compiled an assessment of heightened threat areas ("HTAs") for wildfires that are presented as different tiers to characterize wildfire risk and potential catastrophic wildfire risk. The different tiers that the Nevada Utilities use to categorize their HTAs are Tier 1, Tier 1E - Elevated ("Tier 1E"), Tier 2 (high) and Tier 3 (extreme).

Approximately 2,720 miles, or 9%, of the Nevada Utilities' transmission and distribution lines are in Tier 1E, Tier 2 and Tier 3 HTAs, covering approximately 6% of its service territory and approximately 0.2% of its customer base.

As of December 31, 2024, the 2,720 miles of transmission and distribution lines in Tier 1E, Tier 2 and Tier 3 HTAs were as follows:

- 1,930 miles, or 71%, with bare conductor miles, a portion of which in Tier 3 is fully mitigated by system relay fast trip protection schemes that are expanding into Tiers 2 and 1E with estimated completion by the end of 2026;
- 20 miles, or 1%, with new covered conductor miles; and
- 770 miles, or 28%, with underground miles.

The on-going asset hardening of the HTAs is a priority for the Nevada Utilities and a key part of the developed wildfire mitigation plans.

Refer to "Future Uses of Cash" in Item 7 of this Form 10-K for further discussion of the Nevada Utilities' natural disaster protection plan related capital expenditures, including asset hardening.

Enhanced Safety Settings

Enhanced safety settings are available across the HTAs in the Nevada Utilities' service territory. Upon declaration of wildfire season, the Nevada Utilities place all Tier 3 circuits and certain Tier 2 and Tier 1E circuits into fire season mode with no circuit reclosing which reduces the potential for sparking on multiple reclosing events when faults occur. Additionally, Fast Trip Fire Mode is an instantaneous lockout setting available at most HTA substations that is enabled when certain risk conditions are present to provide an enhanced level of protection to limit the potential for wildfire ignition.

Meteorology and Risk Modeling

The Nevada Utilities have installed 65 weather stations that monitor weather conditions and model the impact to the electrical infrastructure. These weather stations combined with the Nevada Utilities' dedicated full-time meteorologist provide the Nevada Utilities with the ability to forecast weather and fire risk impact data twice daily. The Nevada Utilities will continue to install additional weather stations to refine weather modeling in areas where geographic terrain conditions require a dense network of weather stations in order to provide the necessary granular data. The Nevada Utilities have also installed 25 fire cameras equipped with artificial intelligence that provide around-the-clock monitoring and alerts of new fire starts.

Asset Inspection Program

Within the identified HTAs, the Nevada Utilities conduct an annual inspection of overhead facilities with an accelerated correction timeline for any conditions noted. A detailed inspection of facilities located in HTAs is conducted every three to 10 years based on the identified risk level.

Vegetation Management

The Nevada Utilities' vegetation management program consists of prioritized patrols and inspections and vegetation clearing work including right-of-way clearing, tree trimming and ground clearing of equipment poles in all HTAs. The Nevada Utilities collaborate with state and federal agencies for enhanced ground clearing to create resilient corridors of cleared vegetation to deter fire spread.

Public Safety Outage Management and Wildfire Encroachment Policy

A PSOM is used as a preventative measure prior to extraordinary weather conditions that may pose threats to the public, customers, infrastructure or the environment where the electrical network is de-energized proactively under certain conditions. This program includes areas of wildfire risk in Tier 3, Tier 2 and Tier 1E where proactive de-energization zones are identified. In determining whether to initiate a PSOM, the Nevada Utilities evaluate conditions that may create an unacceptable level of risk of electric infrastructure being damaged and causing an ignition using data from meteorological systems and forecasting tools. During 2024, the Nevada Utilities continued to actively utilize the PSOM program to address extreme-risk weather conditions. The Nevada Utilities' also have a wildfire encroachment policy under which it will de-energize its lines when a known wildfire is within a specified distance of its assets. PSOM is an increasingly common practice for utilities to use as part of wildfire mitigation.

Future Generation, Conservation and Energy Efficiency

Energy Supply Planning

Within the energy supply planning process, there are four key components covering different time frames:

- IRPs are filed by the Nevada Utilities for approval by the PUCN every three years and the Nevada Utilities may, as necessary, file amendments to their IRPs. IRPs are prepared in compliance with Nevada laws and regulations and cover a 20-year period. Nevada law governing the IRP process was modified in 2017 and now requires joint filings by Nevada Power and Sierra Pacific. IRPs develop a comprehensive, integrated plan that considers customer energy requirements and propose the resources to meet those requirements in a manner that is consistent with prevailing market fundamentals. The ultimate goal of the IRPs is to balance the objectives of minimizing costs and reducing volatility while reliably meeting the electric needs of the Nevada Utilities' customers. Costs incurred to complete projects approved through the IRP process still remain subject to review for reasonableness by the PUCN.
- Energy Supply Plans ("ESP") are filed with the PUCN for approval and operate in conjunction with the PUCN-approved 20-year IRP. The ESP has a one- to three-year planning horizon and is an intermediate-term resource procurement and risk management plan that establishes the supply portfolio strategies within which intermediate-term resource requirements will be met with PUCN approval required for executing contracts of longer than three years.
- Distributed Resource Plans ("DRP") are filed with the PUCN for approval and operate in conjunction with the PUCN-approved 20-year IRP. The DRP establishes a formal process to aid in the cost-effective integration of distributed resources into the Nevada Utilities' distribution and transmission process and ultimately the NV Energy utilities' electricity grid.
- Action plans are filed with the PUCN for approval and operate in conjunction with the PUCN-approved 20-year IRP and PUCN-approved ESP. The action plan establishes tactical execution activities with a three-year focus.

In August 2023, the Nevada Utilities filed its Joint Application for approval of the Fifth Amendment to the 2021 Joint Integrated Resource Plan. The Fifth Amendment sought, in part (1) to convert the existing coal-fueled generating facility at North Valmy Generating Station to a cleaner natural gas-fueled generating facility (2) to purchase, install, and operate a company-owned 400 MW solar plant along with a 400 MW, four-hour battery storage system in Northern Nevada; (3) to continue operation of Tracy units 4 and 5 to 2049; (4) to purchase development assets for the 149 MW photovoltaic and 149 MW battery energy storage system Crescent Valley Solar project; (5) to construct the Esmeralda and Amargosa substations transformers; and (6) to construct the necessary infrastructure in the APEX Area Master Plan. The Nevada Utilities sought approval of approximately \$1.8 billion in total costs of new projects. An order was issued in March 2024 in which the Nevada Utilities filed a motion for clarification and petition for reconsideration. In April 2024, a modified final order was issued, which granted in part and denied in part including the denial of the 149 MW photovoltaic and 149 MW battery energy storage system Crescent Valley Solar project as delineated in the final modified order.

In May 2024, the Nevada Utilities filed its joint Application for approval of the 2024 Joint Integrated Resources Plan. The 2024 joint Application sought, in part (1) the addition of three power purchase agreements for solar generating resources totaling more than 1,000 MW, each with co-located battery storage systems; (2) the addition of 400 MW of company-owned hydrogen-capable natural gas simple cycle combustion turbine peakers at the North Valmy generation station; (3) to approve an update of the Greenlink Nevada Transmission project costs; and (4) to construct the necessary transmission infrastructure to support growing customer demand. In December 2024, the PUCN largely accepted the filing as filed but denied opining on the additional costs associated with the Greenlink Nevada project as all costs expended to construct the previously approved Greenlink Nevada project are subject to a prudence review in the GRC as delineated in the final 2024 Joint Integrated Resource Plan order.

Energy Efficiency Programs

The Nevada Utilities have provided a comprehensive set of DSM programs which include energy efficiency, demand response, and conservation programs to their Nevada electric customers. The programs are designed to reduce energy consumption and more effectively manage when energy is used, including management of seasonal peak loads. Current programs offer services to customers such as energy audits and customer education and awareness efforts that provide information on how to improve the efficiency of their homes and businesses. To assist customers in investing in energy efficiency, the Nevada Utilities have offered rebates or incentives encouraging the purchase and installation of high-efficiency equipment such as lighting, heating and cooling equipment, electric water heating, weatherization, motors, process equipment and systems, as well as incentives for efficient construction. Incentives are also paid to residential customers who participate in the air conditioner load control program and nonresidential customers who participate in the smart thermostat and energy storage demand response program and nonresidential load management program. Energy efficiency program costs are recovered through annual rates set by the PUCN and adjusted based on the Nevada Utilities' annual filing to recover current program costs and any over or under collections from the prior filing, subject to prudence review. During 2024, Nevada Power spent \$45 million on energy efficiency programs, resulting in an estimated 213,393 MWhs of electric energy savings and an estimated 173 MWs of electric peak load management. During 2024, Sierra Pacific spent \$13 million on energy efficiency programs, resulting in an estimated 51,199 MWhs of electric energy savings and an estimated 27 MWs of electric peak load management.

Regulated Natural Gas Operations

Sierra Pacific is engaged in the distribution of natural gas to customers in its service territory and the related procurement, transportation and storage of natural gas for the benefit of those customers. Sierra Pacific purchases natural gas from various suppliers and contracts with interstate natural gas pipelines for transportation of the natural gas from the production areas to Sierra Pacific's service territory and for storage services to manage fluctuations in system demand and seasonal pricing. Sierra Pacific sells natural gas and delivery services to end-use customers on its distribution system; sells natural gas to other utilities, municipalities and energy marketing companies; and transports natural gas through its distribution system for a number of end-use customers who have independently secured their supply of natural gas. During 2024, 7% of the total natural gas delivered through Sierra Pacific's distribution system was for transportation service.

Natural gas property consists primarily of natural gas mains and service lines, meters, and related distribution equipment, including feeder lines to communities served from natural gas pipelines owned by others. The natural gas distribution facilities of Sierra Pacific included 3,700 miles of natural gas mains and service lines as of December 31, 2024.

Customer Usage and Seasonality

The percentages of natural gas sold to Sierra Pacific's retail and wholesale customers by class of customer, total Dths of natural gas sold, total Dths of transportation service and the average number of retail customers for the years ended December 31 were as follows:

	2024	2023	2022
Dths sold:			
Residential	54 %	52 %	55 %
Commercial ⁽¹⁾	27	26	28
Industrial ⁽¹⁾	12	12	11
Total retail	93	90	94
Wholesale ⁽²⁾	7	10	6
	100 %	100 %	100 %
Dths of natural gas sold (in thousands):	20,379	23,613	20,622
Dths of transportation service (in thousands):	1,267	1,453	1,576
Average number of retail customers (in thousands):			
Residential	171	169	166
Commercial	14	14	14
Industrial	—	—	—
Total	185	183	180

(1) Commercial and industrial customers are classified primarily based on the nature of their business and natural gas usage. Commercial customers are non-residential customers with monthly gas usage less than 12,000 therms during five consecutive winter months. Industrial customers are non-residential customers that use natural gas in excess of 12,000 therms during one or more winter months.

(2) Wholesale sales are generally made to other utilities, municipalities and energy marketing companies for eventual resale to end-use customers.

There are seasonal variations in Sierra Pacific's regulated natural gas business that are principally due to the use of natural gas for heating. Typically, 47-58% of Sierra Pacific's regulated natural gas revenue is reported in the months of December through March.

During the winter months of 2024, 2023 and 2022, Sierra Pacific's peak-day natural gas delivery through its gas distribution system was 140,157, 160,974 and 152,157 Dths, respectively.

Fuel Supply and Capacity

The purchase of natural gas for Sierra Pacific's regulated natural gas operations is done in combination with the purchase of natural gas for Sierra Pacific's regulated electric operations. In response to energy supply challenges, Sierra Pacific has adopted an approach to managing the energy supply function that has three primary elements, as discussed earlier under Generating Facilities and Fuel Supply. Similar to Sierra Pacific's regulated electric operations, as long as Sierra Pacific's purchases of natural gas are deemed prudent by the PUCN, through its annual prudency review, Sierra Pacific is permitted to recover the cost of natural gas. Sierra Pacific also has the ability, with PUCN approval, to reset quarterly the BTERs, based on the last 12 months fuel costs, and to reset quarterly DEAA.

Human Capital

Employees

As of December 31, 2024, Nevada Power had approximately 1,500 employees, of which approximately 800 were covered by a union contract with the International Brotherhood of Electrical Workers.

As of December 31, 2024, Sierra Pacific had approximately 1,100 employees, of which approximately 600 were covered by a union contract with the International Brotherhood of Electrical Workers.

For more information regarding Nevada Power's and Sierra Pacific's human capital disclosures, refer to Item 1. Business - General section of this Form 10-K.

NORTHERN POWERGRID

Northern Powergrid, an indirect wholly owned subsidiary of BHE, is a holding company with investments in two companies that distribute electricity in Great Britain, Northern Powergrid (Northeast) plc and Northern Powergrid (Yorkshire) plc. In addition to the Northern Powergrid Distribution Companies, Northern Powergrid also has investments in a meter asset rental business that leases meters to energy suppliers in the United Kingdom, an engineering contracting business that provides electrical infrastructure contracting services primarily to third parties, an upstream gas exploration and production business that is focused on developing integrated projects in Europe and Australia and two solar generation facilities in Australia having a total net owned capacity of 260 MWs.

The Northern Powergrid Distribution Companies serve 4.0 million end-users and operate in the north-east of England from North Northumberland through Tyne and Wear, County Durham and Yorkshire to North Lincolnshire, an area covering 10,000 square miles. The principal function of the Northern Powergrid Distribution Companies is to build, maintain and operate the electricity distribution network through which the end-user receives a supply of electricity.

The Northern Powergrid Distribution Companies receive electricity from the national grid transmission system and from generators that are directly connected to the distribution network and distribute it to end-users' premises using their networks of transformers, switchgear and distribution lines and cables. Substantially all of the end-users in the Northern Powergrid Distribution Companies' distribution service areas are directly or indirectly connected to the Northern Powergrid Distribution Companies' networks and electricity can only be delivered to these end-users through their distribution systems, thus providing the Northern Powergrid Distribution Companies with distribution volumes that are relatively stable from year to year. The Northern Powergrid Distribution Companies charge fees for the use of their distribution systems to the suppliers of electricity.

The suppliers purchase electricity from generators, sell the electricity to end-user customers and use the Northern Powergrid Distribution Companies' distribution networks pursuant to an industry standard "Distribution Connection and Use of System Agreement." During 2024, E.ON and certain of its affiliates and British Gas Trading Limited represented 17% and 14%, respectively, of the total combined distribution revenue of the Northern Powergrid Distribution Companies. Variations in demand from end-users can affect the revenues that are received by the Northern Powergrid Distribution Companies in any year, but such variations have no effect on the total revenue that the Northern Powergrid Distribution Companies are allowed to recover in a price control period. Under- or over-recoveries against price-controlled revenues are carried forward into prices for future years.

The Northern Powergrid Distribution Companies' combined service territory features a diverse economy with no dominant sector. The mix of rural, agricultural, urban and industrial areas covers a broad customer base ranging from domestic usage through farming and retail to major industry including automotives, chemicals, mining, steelmaking and offshore marine construction. The industry within the area is concentrated around the principal centers of Newcastle, Middlesbrough, Sheffield and Leeds.

The price-controlled revenue of the Northern Powergrid Distribution Companies is set out in the special conditions of the licenses of those companies. The licenses are enforced by the regulator, GEMA, through Ofgem, and limit increases to allowed revenues (or may require decreases) based upon the rate of inflation, other specified factors and other regulatory action. The current electricity distribution price control became effective April 1, 2023 and will continue through March 31, 2028.

GWhs and percentages of electricity distributed to the Northern Powergrid Distribution Companies' end-users and the total number of end-users as of and for the years ended December 31 were as follows:

	2024		2023		2022	
GWhs distributed:						
Residential	12,045	38 %	11,638	38 %	11,880	37 %
Commercial	3,391	11	3,534	11	3,737	12
Industrial	15,508	50	15,655	50	16,239	50
Other	280	1	279	1	301	1
	<u>31,224</u>	<u>100 %</u>	<u>31,106</u>	<u>100 %</u>	<u>32,157</u>	<u>100 %</u>
Number of end-users (in thousands):	<u>3,952</u>		<u>3,954</u>		<u>3,953</u>	
Northern Powergrid (Northeast) plc	1,619		1,621		1,620	
Northern Powergrid (Yorkshire) plc	2,333		2,333		2,333	

As of December 31, 2024, the combined electricity distribution network of the Northern Powergrid Distribution Companies included approximately 17,100 miles of overhead lines, 44,600 miles of underground cables and 860 major substations.

BHE PIPELINE GROUP (EASTERN ENERGY GAS AND EGTGS)

The BHE Pipeline Group consists of BHE GT&S, Northern Natural Gas and Kern River, each an indirect wholly owned subsidiary of BHE. The BHE Pipeline Group operates approximately 21,000 miles of pipeline with a design capacity of approximately 21.5 Bcf of natural gas per day, transported approximately 14% of the total natural gas consumed in the U.S. during 2024 and owns assets in 27 states. The BHE Pipeline Group also operates 22 natural gas storage facilities with a total working gas capacity of 515.6 Bcf and an LNG export, import and storage facility. BHE Pipeline Group, LLC's operations also include a company specializing in environmentally clean, low-emission, large-horsepower contract compression services. As of December 31, 2024, the BHE Pipeline Group had approximately 2,800 employees, consisting of approximately 2,300 natural gas operations employees and 500 corporate services employees.

The Pipeline Companies compete with other pipelines on the basis of cost, flexibility, reliability of service and overall customer service, with the customer's decision being made primarily on the basis of delivered price, which includes both the natural gas commodity cost and transportation costs. The Pipeline Companies also compete with midstream operators and gas marketers seeking to provide or arrange transportation, storage and other services to meet customer needs. Natural gas competes with alternative energy sources, including coal, nuclear energy, wind, geothermal, solar and fuel oil and the electricity generated from these alternative energy sources. The Pipeline Companies generate a substantial portion of their revenue from long-term firm contracts for transportation and storage services and are therefore insulated from competitive factors during the terms of the contracts. When these long-term contracts expire, the Pipeline Companies face competitive pressures from other natural gas pipeline facilities.

Subject to regulatory requirements, the Pipeline Companies attempt to recontract or remarket capacity at the maximum rates allowed under their tariffs, although at times the Pipeline Companies discount these rates to remain competitive. Historically, the Pipeline Companies have been able to provide competitively priced services because of access to a variety of relatively low cost supply basins, cost control measures and the relatively high level of firm entitlement that is sold on a seasonal and annual basis, which lowers the per unit cost of transportation. To date, the Pipeline Companies have avoided significant pipeline system bypasses.

BHE GT&S

BHE GT&S' operations, through its investment in Eastern Energy Gas, includes three interstate natural gas pipeline systems, one of the nation's largest underground natural gas storage systems and one LNG export, import and storage facility. BHE GT&S' operations also include smaller LNG facilities and a gathering and processing company.

Eastern Energy Gas' principal subsidiaries are EGTS and CGT. EGTS' operations include natural gas transmission system assets located in Maryland, New York, Ohio, Pennsylvania, Virginia and West Virginia. EGTS also operates one of the nation's largest underground natural gas storage systems located in New York, Pennsylvania and West Virginia. CGT's operations include an interstate natural gas transmission system located in South Carolina and Georgia. Eastern Energy Gas also holds a 50% equity interest in Iroquois. Iroquois owns and operates an interstate natural gas transmission system located in the states of New York and Connecticut.

Eastern Energy Gas' LNG operations involve the export, import and storage of LNG at the Cove Point LNG Facility that is owned by Cove Point, located in Maryland, as well as the transmission of regasified LNG to the interstate pipeline grid and mid-Atlantic markets and the liquefaction of natural gas for export as LNG. Cove Point's LNG Facility has an operational peak regasification daily send-out capacity of approximately 1.8 million Dths and an aggregate LNG storage capacity of approximately 14.6 billions of cubic feet equivalent ("Bcfe"). In addition, Cove Point has a small liquefier that has the potential to produce approximately 15,000 Dth/day. The Liquefaction Facility consists of one LNG train with a nameplate outlet capacity of 5.25 million tonnes per annum ("Mtpa"). Cove Point has authorization from the DOE to export up to 0.77 Bcfe/day (approximately 5.75 Mtpa) should the Liquefaction Facility perform better than expected. Cove Point's 36-inch diameter underground interstate natural gas pipelines are approximately 139 miles, with interconnections to Transcontinental Gas Pipeline, LLC in Fairfax County, Virginia, and with Columbia Gas Transmission, LLC and EGTS in Loudoun County, Virginia. Eastern Energy Gas operates, as the general partner, and holds 75% of the limited partner interests in the Cove Point export, import and storage facility. BHE GT&S also operates and has interests in three smaller LNG facilities in Alabama, Florida and Pennsylvania.

In total, Eastern Energy Gas operates approximately 5,400 miles of natural gas transmission, gathering and storage pipelines, of which approximately 5,200 miles are owned by Eastern Energy Gas, with a design capacity of 12.9 Bcf per day as well as approximately 100 miles of natural gas liquids pipelines operated by BHE GT&S. EGTS operates approximately 3,900 miles of natural gas transmission and storage pipelines with a design capacity of 10.1 Bcf per day. EGTS also operates 17 underground storage fields with a total working gas capacity of approximately 420 Bcf, of which approximately 307 Bcf relates to natural gas storage field capacity that EGTS owns. BHE GT&S' pipeline system is configured with approximately 360 active receipt and delivery points. In 2024, BHE GT&S delivered over 2.2 trillion cubic feet ("Tcf") of natural gas to its customers.

BHE GT&S' natural gas transmission and storage earnings primarily result from rates established by FERC. Revenues derived from BHE GT&S' pipeline operations are primarily from reservation charges for firm transmission and storage services as provided for in their FERC-approved tariffs. Reservation charges are required to be paid regardless of volumes transported or stored. The profitability of these businesses is dependent on their ability, through the rates they are permitted to charge, to recover costs and earn a reasonable return on their capital investments. As of December 31, 2024, 86% of Eastern Energy Gas' transmission capacity is subscribed, including 79% under long-term contracts and 7% on a year-to-year basis, and 100% of EGTS' storage capacity is subscribed, including 93% under long-term contracts. As of December 31, 2024, the weighted average remaining contract term for Eastern Energy Gas' and EGTS' firm transmission contracts is six years and five years, respectively, and EGTS' storage contracts is three years. Additionally, BHE GT&S receives revenue from firm fee-based contractual arrangements, including negotiated rates, for certain pipeline transmission and LNG storage and terminal services. Variability in BHE GT&S' earnings results from changes in operating and maintenance expenditures, as well as changes in rates and the demand for services, which are dependent on weather, changes in commodity prices and the economy.

BHE GT&S' operating revenue for the year ended December 31 was as follows (in millions):

	2024		2023		2022	
Transmission	\$ 885	40 %	\$ 881	39 %	\$ 849	35 %
LNG	798	37	796	36	790	33
Storage	312	14	329	15	316	13
Gas, liquids and other sales	189	9	233	10	447	19
Total operating revenue	<u>\$ 2,184</u>	<u>100 %</u>	<u>\$ 2,239</u>	<u>100 %</u>	<u>\$ 2,402</u>	<u>100 %</u>

Except for quantities of natural gas owned and managed for operational and system balancing purposes, BHE GT&S does not own the natural gas that is transported through its system.

During 2024, BHE GT&S had two customers that each accounted for greater than 15% of its operating revenue and its 10 largest customers accounted for 49% of its total operating revenue. BHE GT&S has agreements with terms through 2038 to retain the majority of its two largest customers' volumes. The loss of any of these significant customers, if not replaced, could have a material adverse effect on BHE GT&S.

Human Capital

As of December 31, 2024, Eastern Energy Gas had approximately 1,600 employees, consisting of approximately 1,300 natural gas operations employees and 300 corporate services employees. As of December 31, 2024, approximately 600 employees were covered by a union contract with the Utility Workers Union of America.

As of December 31, 2024, EGTS had approximately 1,300 employees, consisting of approximately 1,000 natural gas operations employees and 300 corporate services employees. As of December 31, 2024, approximately 600 employees were covered by a union contract with the Utility Workers Union of America.

For more information regarding Eastern Energy Gas' and EGTS' human capital disclosures, refer to Item 1. Business - General section of this Form 10-K.

Northern Natural Gas

Northern Natural Gas owns the largest interstate natural gas pipeline system in the U.S., as measured by pipeline miles, which reaches from west Texas to Michigan's Upper Peninsula. Northern Natural Gas primarily transports and stores natural gas for utilities, municipalities, gas marketing companies and industrial and commercial users. Northern Natural Gas' pipeline system consists of two commercial segments. Its traditional end-use and distribution market area in the northern part of its system, referred to as the Market Area, includes points in Iowa, Nebraska, Minnesota, Wisconsin, South Dakota, Michigan and Illinois. Its natural gas supply and delivery service area in the southern part of its system, referred to as the Field Area, includes points in Kansas, Texas, Oklahoma and New Mexico. The Market Area and Field Area are separated at a Demarcation Point ("Demarc"). Northern Natural Gas' pipeline system consists of 14,200 miles of natural gas pipelines, including 5,800 miles of mainline transmission pipelines and 8,400 miles of branch and lateral pipelines, with a Market Area design capacity of 6.4 Bcf per day, a Field Area delivery capacity of 1.7 Bcf per day to the Market Area and 1.5 Bcf per day to the West Texas area and 95.6 Bcf of working gas capacity in five storage facilities. Northern Natural Gas' pipeline system is configured with approximately 2,335 active receipt and delivery points which are integrated with the facilities of LDCs. Many of Northern Natural Gas' LDC customers are part of combined utilities that also use natural gas as a fuel source for electric generation. Northern Natural Gas delivered over 1.3 Tcf of natural gas to its customers in 2024.

Northern Natural Gas' transportation rates and most of its storage rates are cost-based. These rates are designed to provide Northern Natural Gas with an opportunity to recover its costs of providing services and earn a reasonable return on its investments. Substantially all of Northern Natural Gas' Market Area transportation revenue is generated from reservation charges, with the balance from usage charges. Most of Northern Natural Gas' transportation capacity in the Market Area is committed to customers under firm transportation contracts, where customers pay Northern Natural Gas a monthly reservation charge for the right to transport natural gas through Northern Natural Gas' system. Reservation charges are required to be paid regardless of volumes transported or stored. As of December 31, 2024, approximately 81% of Northern Natural Gas' customers' entitlement in the Market Area have terms beyond 2026 and approximately 39% beyond 2028. As of December 31, 2024, the weighted average remaining contract term for Northern Natural Gas' Market Area firm transportation contracts is five years. Northern Natural Gas' Field Area customers consist primarily of energy marketing companies, midstream companies and power generators that are connected to Northern Natural Gas' system in Texas and New Mexico that are contracted on a long-term basis with a weighted average remaining contract term of six years. Northern Natural Gas' storage services are provided through the operation of one underground natural gas storage field in Iowa and two underground natural gas storage facilities in Kansas. Additionally, Northern Natural Gas has two LNG storage peaking units, one in Iowa and one in Minnesota, that support its transportation service. The three underground natural gas storage facilities and two LNG storage peaking units have a total working gas capacity of over 95.6 Bcf and approximately 2.2 Bcf per day of peak delivery capability. The average remaining contract term for firm storage contracts is four years.

Northern Natural Gas' operating revenue for the years ended December 31 was as follows (in millions):

	2024		2023		2022	
Transportation:						
Market Area	\$ 832	64 %	\$ 815	65 %	\$ 688	62 %
Field Area	281	22	249	22	210	18
Total transportation	1,113	86	1,064	87	898	80
Storage	113	8	113	9	97	9
Total transportation and storage revenue	1,226	94	1,177	96	995	89
Gas, liquids and other sales	73	6	49	4	123	11
Total operating revenue	<u>\$ 1,299</u>	<u>100 %</u>	<u>\$ 1,226</u>	<u>100 %</u>	<u>\$ 1,118</u>	<u>100 %</u>

Except for quantities of natural gas owned and managed for operational and system balancing purposes, Northern Natural Gas does not own the natural gas that is transported through its system. The sale of natural gas for operational and system balancing purposes accounts for the majority of the remaining operating revenue.

During 2024, Northern Natural Gas had two customers that each accounted for greater than 10% of its transportation and storage revenue and its 10 largest customers accounted for 62% of its system-wide transportation and storage revenue. Northern Natural Gas has agreements with terms through 2027 and 2034 to retain the majority of its two largest customers' volumes. The loss of either of these significant customers, if not replaced, could have a material adverse effect on Northern Natural Gas.

Kern River

Kern River owns an interstate natural gas pipeline system that extends from supply areas in the Rocky Mountains to consuming markets in Utah, Nevada and California. Kern River's pipeline system consists of 1,700 miles of natural gas pipelines, including 1,400 miles of mainline section and 300 miles of common facilities, with a year-round design capacity of 2,166,575 Dths, or 2.2 Bcf, per day. Additional seasonal design capacity (Bell-Curve) is contracted in all months except July, August and September. Kern River owns the entire mainline section, which extends from the system's point of origination near Opal, Wyoming, through the Central Rocky Mountains to Daggett, California. The mainline section consists of 1,300 miles of primarily 36-inch diameter pipeline and 100 miles of various laterals that connect to the mainline. The common facilities are jointly owned by Kern River and Mojave Pipeline Company as tenants-in-common and are operated by Mojave Pipeline Operating Company.

Kern River's rates are designed to provide Kern River with an opportunity to recover its costs of providing services and earn a reasonable return on its investments and are based on a levelized rate design that assumes recovery of 70% of the original investment during the initial long-term contracts ("Period One rates"). After expiration of the initial term, eligible customers have the option to elect service at rates ("Period Two rates") that are lower than Period One rates because they are designed to recover the remaining 30% of the original investment. To the extent that eligible customers do not contract for service at Period Two rates, the volumes are turned back to Kern River, and it resells capacity at market rates for varying terms. As of December 31, 2024, Kern River's design capacity, including seasonal Bell-Curve, totaled 2,345,381 Dths per day and approximately 91% is contracted pursuant to long-term firm natural gas transportation service agreements, whereby Kern River receives natural gas on behalf of customers at designated receipt points and transports the natural gas on a firm basis to designated delivery points. In return for this service, each customer pays Kern River a fixed monthly reservation fee based on each customer's maximum daily quantity, which represents nearly 87% of total operating revenue, and a commodity charge based on the actual amount of natural gas transported pursuant to its long-term firm natural gas transportation service agreements and Kern River's tariff. These long-term firm natural gas transportation service agreements expire between October 2025 and December 2045 and have a weighted-average remaining contract term of over six years. As of December 31, 2024, 74% of the year-round design capacity of 2,166,575 Dths under firm contract has primary delivery points in California, with the flexibility to access secondary delivery points in Nevada and Utah.

Kern River primarily transports natural gas for utilities, municipalities, energy marketing companies, electric generating companies and other industrial and commercial users. Except for quantities of natural gas owned for operational purposes, Kern River does not own the natural gas that is transported through its system. Kern River's transportation rates are cost-based.

During 2024, Kern River had three customers, including Nevada Power Company, an affiliated company, that each accounted for greater than 10% of its revenue. The loss of these significant customers, if not replaced, could have a material adverse effect on Kern River.

BHE TRANSMISSION

BHE Transmission consists of BHE Canada, an indirect wholly owned subsidiary of BHE, BHE U.S. Transmission, a wholly owned subsidiary of BHE, interests in generating facilities and 300 MWs of long-term northbound transmission rights on the Montana Alberta Tie Line (commencing April 30, 2026). BHE Canada and BHE U.S. Transmission together own and operate the Montana Alberta Tie Line, which is a 214-mile, 230-kV transmission line that runs from Lethbridge, Alberta, Canada to Great Falls, Montana, U.S. and connects power grids in the two jurisdictions. BHE Canada also owns AlbertaEx, a cross-border operations center to optimize in real-time the value of BHE Transmission's existing physical generation assets on the Montana Alberta Tie Line. Operations for AlbertaEx commenced in January 2025.

BHE Canada

BHE Canada primarily consists of AltaLink, a regulated electric transmission utility company headquartered in Alberta, Canada, serving approximately 85% of Alberta's population. AltaLink's high voltage transmission lines and related facilities transmit electricity from generating facilities to major load centers, cities and large industrial plants throughout its 87,000 square mile service territory, which covers a diverse geographic area including most major urban centers in central and southern Alberta. AltaLink's transmission facilities, consisting of approximately 8,300 miles of transmission lines and approximately 310 substations as of December 31, 2024, are an integral part of the Alberta Interconnected Electric System ("AIES").

The AIES is a network or grid of transmission facilities operating at high voltages ranging from 69 kV to 500 kV. The grid delivers electricity from generating units across Alberta, Canada, through approximately 16,000 miles of transmission lines. The AIES is interconnected to British Columbia's transmission system and to Montana's transmission system that link Alberta with the North American western interconnected system. The AIES is also interconnected with Saskatchewan's transmission system that links Alberta with the North American eastern interconnection.

AltaLink is a transmission facility owner within the electricity industry in Alberta and is permitted to charge a tariff rate for the use of its transmission facilities. Such tariff rates are established on a cost-of-service regulatory model, which is designed to allow AltaLink an opportunity to recover its costs of providing services and to earn a reasonable return on its investments. Transmission tariff rates are approved by the AUC and are collected from the AESO.

The electricity industry in Alberta consists of four principal segments. Generators sell wholesale power into the power pool operated by the AESO and through direct contractual arrangements. Alberta's transmission system or grid is composed of high voltage power lines and related facilities that transmit electricity from generating facilities to distribution networks and directly connected end-users. Distribution facility owners are regulated by the AUC and are responsible for arranging for, or providing, regulated rate and regulated default supply services to convey electricity from transmission systems and distribution-connected generators to end-use customers. Retailers can procure energy through the power pool, through direct contractual arrangements with energy suppliers or ownership of generation facilities and arrange for its distribution to end-use customers.

The AESO mandate is defined in the *Electric Utilities Act* (Alberta) and its regulations and requires the AESO to assess both current and future needs of the AIES. In January 2025, the AESO released the 2025 Long-Term Transmission Plan. The Long-Term Transmission Plan seeks to optimize the use of the existing transmission system and plan the development of new transmission to ensure a safe and reliable electricity system that enables a fair, efficient, and openly competitive electricity market. The 2025 Long-Term Transmission Plan identifies approximately C\$2,100 million of generation driven projects and C\$150 million of intertie driven projects in AltaLink's service territory with in-service dates before 2030 under the current zero-congestion policy. The AESO acknowledges that the ongoing workstream to develop and implement the Optimal Transmission Planning framework will impact the need and timing for generation growth driven projects.

In May 2024, the AESO released its 2024 Long-Term Outlook. The reference case was consistent with the Government of Alberta's target to achieve decarbonization by 2050. The alternatives focused on the following three scenarios:

- Decarbonization by 2035: a scenario which assumes a linear decline in emissions from 2030 to 2035 based on federal Clean Electricity Regulations restrictions;
- Alternative Decarbonization: a scenario which explores the effect of increasing intertie connections in 2035 and anticipates technological cost declines as well as delays in development of carbon capture, utilization and storage, nuclear small modular reactors and hydrogen; and
- High Electrification: a scenario which anticipates higher load growth from increased electric vehicles, electrification of building heating and cooling as well as additional industrial load due to electrification and carbon capture, utilization and storage adoption.

The scenarios allow the AESO to consider possible future states of the Alberta market.

Wildfire Mitigation Plans

AltaLink has developed and implemented detailed wildfire mitigation plans for its service territory since 2019. AltaLink submits these plans to the AUC for approval as part of its General Tariff Application ("GTA") process. AltaLink received approval for its wildfire mitigation plan in the 2019-2021, 2022-2023, and 2024-2025 GTA periods. These plans include improvements in situational awareness, meteorological systems, and risk modeling; investments in asset hardening and vegetation management; and AltaLink's ongoing elevated wildfire risk operating practices and policies, which include inspections, recloser blocking procedures, wildfire encroachment procedures, and PSPS.

Asset Hardening and Vegetation Management

AltaLink continues to invest in specific asset improvements to reduce the risk of wildfire ignition from AltaLink's operations. These hardening efforts reduce the likelihood of AltaLink's transmission lines igniting a wildfire at locations of high fire risk. Investments are primarily focused on targeted transmission structure or transmission line upgrades, or identified right-of-way improvements to remove hazardous vegetation to reduce fire ignition risk.

Situational Awareness, Meteorology, and Risk Modeling

AltaLink uses available integrated meteorology, fire monitoring and camera systems available from the Alberta Government. Additionally, AltaLink has installed incremental weather and camera stations in support of improvements to its situational awareness. This weather information, combined with expert third-party assessment, provides weather and fire risk forecasting daily for AltaLink's service territory. AltaLink also established a Daily Hazard Forecast Report, which is provided to the organization and field crews, and implemented an information portal in the control room. AltaLink initially completed its fire risk modeling and HRFA mapping in 2020 and is planning to complete an update of the static risk modeling in 2025. AltaLink implemented further enhancements to its fire weather modeling tools in 2024. AltaLink completes regular periodic policy updates and training regarding field operations and contractor crew fire management and preventive practices.

Asset Inspection Program

AltaLink completes asset inspections for all its facilities on at least an annual basis. For lines located in HRFAs, inspection frequencies are twice per year to review structure and vegetation conditions.

Public Safety Power Shutoff and Wildfire Encroachment Policy

A PSPS is an operating protocol used as a preventative measure of last resort during periods of extreme wildfire risk. It involves de-energizing a transmission line or lines proactively under certain conditions to reduce the risk of wildfire ignition. In determining whether to initiate a PSPS, AltaLink works with local public safety authorities and considers data from its wildfire risk forecasting tools and meteorological systems. If the forecast exceeds thresholds, escalating action is taken proactively starting from the seven-day forecast outlook. AltaLink continues to conduct stakeholder engagement and exercises related to its PSPS process. To mitigate the risk of secondary ignitions from fires on the landscape as well as safety risks to fire fighters on scene, AltaLink also has a wildfire encroachment policy to either disable reclosers or proactively de-energize transmission lines. These measures aim to reduce the risk to public safety. PSPS is an increasingly common practice for utilities to use as part of wildfire mitigation.

BHE U.S. Transmission

BHE U.S. Transmission is engaged in various joint ventures to develop, own and operate transmission assets and is pursuing additional investment opportunities in the U.S. Currently, BHE U.S. Transmission has two joint ventures with transmission assets that are operational: ETT, a 50% owned joint venture with subsidiaries of American Electric Power Company, Inc. ("AEP"), and Prairie Wind Transmission, LLC, a 25% owned joint venture with AEP and Evergy, Inc. ETT owns and operates electric transmission assets in the ERCOT and, as of December 31, 2024, had total assets of \$3.9 billion. ETT's transmission system includes approximately 2,100 miles of transmission lines and 48 substations as of December 31, 2024. Prairie Wind Transmission, LLC, owns and operates a 108-mile, 345-kV transmission project in Kansas having total assets of \$126 million as of December 31, 2024.

Generating Facilities

BHE Transmission has ownership interests in the following generating facilities as of December 31, 2024:

Generating Facility	Location	Energy Source	Year Installed	Power Purchase Agreement Expiration	Power Purchaser	Facility Net Capacity (MWs) ⁽¹⁾	Net Owned Capacity (MWs) ⁽¹⁾
WIND:							
Rattlesnake	Alberta	Wind	2022	2042/2032	Telus, RBC, Bullfrog, Shopify	130	130
Rim Rock ⁽²⁾	Montana	Wind	2012	2026	Morgan Stanley	189	189
Glacier 1 ⁽²⁾	Montana	Wind	2008	2026	Morgan Stanley	106	106
Glacier 2 ⁽²⁾	Montana	Wind	2009	2026	Morgan Stanley	103	103
						528	528
NATURAL GAS:							
Nat-1	Alberta	Natural gas	2015	N/A	N/A	20	20
						20	20
Total Available Generating Capacity						548	548

- (1) Facility Net Capacity represents the lesser of nominal ratings or any limitations under applicable interconnection, power purchase, or other agreements for intermittent resources and the total net dependable capability available during summer conditions for all other units. An intermittent resource's nominal rating is the manufacturer's contractually specified capability (in MWs) under specified conditions. Net Owned Capacity indicates BHE Transmission's ownership of Facility Net Capacity.
- (2) A 75 MW by two-hour battery energy storage system is currently under construction connecting at the Marias substation, servicing the three Montana wind farms, and is expected to be operational in late 2025.

BHE RENEWABLES

The subsidiaries comprising the BHE Renewables reportable segment own interests in several independent power projects in the U.S. The following table presents certain information concerning these independent power projects as of December 31, 2024:

Generating Facility	Location	Energy Source	Year Installed	Power Purchase Agreement Expiration	Power Purchaser ⁽¹⁾	Facility Net Capacity (MWs) ⁽²⁾	Net Owned Capacity (MWs) ⁽²⁾
WIND:							
Grande Prairie	Nebraska	Wind	2016	2036	OPPD	400	400
Jumbo Road	Texas	Wind	2015	2033	AE	300	300
Santa Rita	Texas	Wind	2018	2025-2038	KC, CODTX, MES	300	300
Mariah Del Norte	Texas	Wind	2016	N/A	N/A	230	230
Walnut Ridge	Illinois	Wind	2018	2028	USGSA	212	212
Flat Top	Texas	Wind	2019	2038	Shaw	200	200
Pinyon Pines I	California	Wind	2012	2035	SCE	168	168
Fluvanna II	Texas	Wind	2019	2034	Heinz	158	158
Pinyon Pines II	California	Wind	2012	2035	SCE	132	132
Bishop Hill II	Illinois	Wind	2012	2032	Ameren	81	81
Marshall	Kansas	Wind	2016	2036	MJMEC, KPP, KMEA & COIMO	72	72
Independence	Iowa	Wind	2021	2041	CIPCO	54	54
						2,307	2,307

SOLAR:							
Topaz	California	Solar	2013-2014	2039	PG&E	550	550
Solar Star 1	California	Solar	2013-2015	2035	SCE	310	310
Solar Star 2	California	Solar	2013-2015	2035	SCE	276	276
Agua Caliente	Arizona	Solar	2012-2013	2039	PG&E	290	142
Alamo 6	Texas	Solar	2017	2042	CPS	110	110
Community Solar Gardens ⁽⁵⁾	Minnesota	Solar	2016-2018	2041-2043	(4)	98	98
Pearl	Texas	Solar	2017	2042	CPS	50	50
						<u>1,684</u>	<u>1,536</u>
NATURAL GAS:							
Cordova	Illinois	Natural Gas	2001	N/A	N/A	512	512
Power Resources	Texas	Natural Gas	1988	N/A	N/A	140	140
Saranac	New York	Natural Gas	1994	N/A	N/A	245	196
Yuma	Arizona	Natural Gas	1994	N/A	N/A	50	50
						<u>947</u>	<u>898</u>
GEO THERMAL:							
Imperial Valley Projects	California	Geothermal	1982-2000	(3)	(3)	345	345
						<u>345</u>	<u>345</u>
HYDROELECTRIC:							
Wailuku	Hawaii	Hydroelectric	1993	2028	HELCO	10	10
						<u>10</u>	<u>10</u>
Total Available Generating Capacity						<u><u>5,293</u></u>	<u><u>5,096</u></u>
PROJECTS UNDER CONSTRUCTION							
Solar Star 3 & 4 ⁽⁶⁾	California	Solar	Est. 2025	(7)	CPA	48	48
Ravenswood ⁽⁸⁾	West Virginia	Solar	Est. 2025-2027	(9)	TIMET	106	106
						<u><u>5,447</u></u>	<u><u>5,250</u></u>

- (1) Omaha Public Power District ("OPPD"); Austin Energy ("AE"); Kimberly-Clark Corporation ("KC"); City of Denton, TX ("CODTX"); MidAmerican Energy Services, LLC ("MES"); U.S. General Services Administration ("USGSA"); Shaw Industries Group, Inc ("Shaw"); Southern California Edison ("SCE"); Kraft Heinz Food Company ("Heinz"); Ameren Illinois Company ("Ameren"); Missouri Joint Municipal Electric Commission ("MJMEC"); Kansas Power Pool ("KPP"); Kansas Municipal Energy Agency ("KMEA"); City of Independence, MO ("COIMO"); Central Iowa Power Cooperative ("CIPCO"); Pacific Gas and Electric Company ("PG&E"); CPS Energy ("CPS"); Hawaii Electric Light Company, Inc. ("HELCO"); Clean Power Alliance of Southern California ("CPA"); and Titanium Metals Corporation ("TIMET").
- (2) Facility Net Capacity represents the lesser of nominal ratings or any limitations under applicable interconnection, power purchase, or other agreements for intermittent resources and the total net dependable capability available during summer conditions for all other units. An intermittent resource's nominal rating is the manufacturer's contractually specified capability (in MWs) under specified conditions. Net Owned Capacity indicates BHE Renewables' ownership of Facility Net Capacity.
- (3) Approximately 12% of the Company's interests in the Imperial Valley Projects' Contract Capacity are currently sold to Southern California Edison Company under a long-term power purchase agreement expiring in 2026. Certain long-term power purchase agreement renewals for 252 MWs have been entered into with other parties at fixed prices that expire from 2028 to 2039, of which 202 MWs mature in 2039.
- (4) The power purchasers are commercial, industrial and not-for-profit organizations.
- (5) The community solar gardens project is consolidated in the table above for convenience as it consists of 98 distinct entities that each own an approximately 1-MW solar garden with independent but substantially similar terms and conditions.
- (6) In addition to the 48-MW solar photovoltaic facility, Solar Star 3 & 4 has 46-MW of co-located battery energy storage that will be developed in Kern County, California with commercial operation expected in 2025.
- (7) Solar Star 3 & 4 entered into a 20-year power purchase agreement effective on the commercial operation date.
- (8) In addition to the 106-MW solar photovoltaic facility, Ravenswood has 50-MW of co-located battery energy storage that will be developed in Jackson County, West Virginia with commercial operation expected in multiple phases in 2025 through 2027.
- (9) Pending outcome of negotiations with TIMET.

BHE Renewables' operating revenue derived from the following business activities for the years ended December 31 were as follows (dollars in millions):

	2024		2023		2022	
Solar	\$	451	31 %	\$	427	26 %
Wind		267	18		276	16
Geothermal		138	9		210	12
Hydro		7	—		4	—
Natural gas		97	7		105	6
Retail energy services		515	35		688	40
Total operating revenue	\$	1,475	100 %	\$	1,710	100 %
	\$	477	28 %	\$	477	28 %
		228	13		228	13
		212	12		212	12
		5	—		5	—
		71	4		71	4
		744	43		744	43
	\$	1,737	100 %	\$	1,737	100 %

HOMESERVICES

HomeServices, a wholly owned subsidiary of BHE, is one of the largest residential real estate brokerage firms in the U.S. In addition to providing traditional residential real estate brokerage services, HomeServices offers other integrated real estate services, including mortgage originations and mortgage banking; title and closing services; property and casualty insurance; home warranties; relocation services; and other home-related services. HomeServices' real estate brokerage business is subject to seasonal fluctuations because more home sale transactions tend to close during the second and third quarters of the year. As a result, HomeServices' operating results and profitability are typically higher in the second and third quarters relative to the remainder of the year. HomeServices' owned brokerages currently operate in nearly 820 offices in 34 states and the District of Columbia with approximately 37,700 real estate agents under 48 brand names. The U.S. residential real estate brokerage business is subject to the general real estate market conditions, is highly competitive and consists of numerous local brokers and agents in each market seeking to represent sellers and buyers in residential real estate transactions.

HomeServices' franchise network currently includes 270 franchisees and over 1,400 brokerage offices with approximately 44,700 real estate agents under two brand names, primarily in the U.S. In exchange for certain fees, HomeServices provides the right to use the Berkshire Hathaway HomeServices or Real Living brand names and other related service marks, as well as providing orientation programs, training and consultation services, advertising programs and other services.

GENERAL REGULATION

BHE's regulated subsidiaries and certain affiliates are subject to comprehensive governmental regulation, which significantly influences their operating environment, prices charged to customers, capital structure, costs and, ultimately, their ability to recover costs and earn a reasonable return on invested capital. In addition to the discussion contained herein regarding general regulation, refer to "Regulatory Matters" in Item 1 of this Form 10-K for further discussion regarding certain regulatory matters.

Domestic Regulated Public Utility Subsidiaries

The Utilities are subject to comprehensive regulation by various state, federal and local agencies. The more significant aspects of this regulatory framework are described below.

State Regulation

Historically, state regulatory commissions have established retail electric and natural gas rates on a cost-of-service basis, which are designed to allow a utility the opportunity to recover what each state regulatory commission deems to be the utility's reasonable costs of providing services, including the opportunity to earn a fair and reasonable return on its investments based on its cost of debt and equity. In addition to return on investment, a utility's cost of service generally reflects a representative level of prudent expenses, including cost of sales, operating expense, depreciation and amortization and income and other tax expense, reduced by wholesale electricity and other revenue. The allowed operating expenses are typically based on actual historical costs adjusted for known and measurable or forecasted changes. State regulatory commissions may adjust cost of service for various reasons, including pursuant to a review of: (a) the utility's revenue and expenses during a defined test period, (b) the utility's level of investment and (c) changes in income tax laws. State regulatory commissions typically have the authority to review and change rates on their own initiative; however, they may also initiate reviews at the request of a utility, utility customers or organizations representing groups of customers. In certain jurisdictions, the utility and such parties, however, may agree with one another not to request a review of or changes to rates for a specified period of time.

The retail electric rates of the Utilities are generally based on the cost of providing traditional bundled services, including generation, transmission and distribution services. The Utilities have established ECAMs and other cost recovery mechanisms in certain states, which help mitigate their exposure to changes in costs from those assumed in establishing base rates.

With certain limited exceptions, the Utilities have an exclusive right to serve retail customers within their service territories and, in turn, have an obligation to provide service to those customers. In some jurisdictions, certain classes of customers may choose to purchase all or a portion of their energy from alternative energy suppliers, and in some jurisdictions retail customers can generate all or a portion of their own energy. Under Oregon law, PacifiCorp has the exclusive right and obligation to provide electricity distribution services to all residential and nonresidential customers within its allocated service territory; however, nonresidential customers have the right to choose an alternative provider of energy supply. The impact of this right on PacifiCorp's consolidated financial results has not been material. In Washington, state law does not provide for exclusive service territory allocation. PacifiCorp's service territory in Washington is surrounded by other public utilities with whom PacifiCorp has from time to time entered into service area agreements under the jurisdiction of the WUTC. Under California law, PacifiCorp has the exclusive right and obligation to provide electricity distribution services to all residential and nonresidential customers within its allocated service territory; however, cities, counties and certain other public agencies have the right to choose to generate energy supply or elect an alternative provider of energy supply through the formation of a Community Choice Aggregator ("CCA"). To date, no CCA activity has occurred in PacifiCorp's California service territory. If a CCA is formed, PacifiCorp would continue to provide CCA customers transmission, distribution, metering and billing services and the CCA would provide generation supply. In addition, PacifiCorp would likely be able to collect costs from CCA customers for the generation-related costs that PacifiCorp incurred while they were customers of PacifiCorp. PacifiCorp would remain the electricity provider of last resort for these customers. In Illinois, state law has established a competitive environment so that all Illinois customers are free to choose their retail service supplier. For customers that choose an alternative retail energy supplier, MidAmerican Energy continues to have an ongoing obligation to deliver the supplier's energy to the retail customer. MidAmerican Energy bills the retail customer for such delivery services. MidAmerican Energy also has an obligation to serve customers at regulated cost-based rates and has a continuing obligation to serve customers who have not selected a competitive electricity provider. The impact of this right on MidAmerican Energy's financial results has not been material. In Nevada, Chapter 704B of the Nevada Revised Statutes allows retail electric customers with an average annual load of one MW or more to file a letter of intent and application with the PUCN to acquire electric energy and ancillary services from another energy supplier. The law requires customers wishing to choose a new supplier to receive the approval of the PUCN to meet public interest standards. In particular, departing customers must secure new energy resources that are not under contract to the Nevada Utilities, the departure must not burden the Nevada Utilities with increased costs or cause any remaining customers to pay increased costs and the departing customers must pay their portion of any deferred energy balances, all as determined by the PUCN. SB 547 revised Chapter 704B to establish limits on the amount of load eligible to take service under Chapter 704B and to set those limits as a part of the IRP filed by the Nevada Utilities. Also, the Utilities and the state regulatory commissions are individually evaluating how best to integrate private generation resources into their service and rate design, including considering such factors as maintaining high levels of customer safety and service reliability, minimizing adverse cost impacts and fairly allocating costs among all customers.

In Nevada, large natural gas customers using 12,000 therms per month with fuel switching capability are allowed to participate in the incentive natural gas rate tariff. Once a service agreement has been executed, a customer can compare natural gas prices under this tariff to alternative energy sources and choose its source of natural gas. In addition, natural gas customers using greater than 1,000 therms per day have the ability to secure their own natural gas supplies under the gas transportation tariff.

PacifiCorp

Rate Filings

Under Utah law, the UPSC must issue a written order within 240 days of a public utility's application for a general rate change. Absent an order, the proposed rates go into effect as filed and are not subject to refund. The UPSC may allow interim rates to take effect within 45 days of an application, subject to refund or surcharge, if an adequate prima facie showing is established in hearing that the interim rate change is justified.

In Oregon, the OPUC has the authority to suspend proposed new rates for a period not to exceed more than six months, with an additional three-month extension, beyond the 30-day time period when the new rates would otherwise go into effect. Absent suspension or other action from the OPUC, new rates automatically go into effect 30 days from filing by the utility. Upon suspension by the OPUC, the OPUC is authorized to allow the collection of an interim rate, subject to refund, during the pendency of the OPUC's review of the rate request.

In Wyoming, the WPSC can allow interim rates to go into effect 30 days after the initial application but may require a bond to secure a refund for the amount. The WPSC may suspend the rates for final approval for a period not to exceed 10 months.

In Washington, the WUTC has the authority to suspend proposed new rates, subject to hearing, for a period not to exceed 10 months beyond the 30-day time period when the new rate would otherwise go into effect.

Under Idaho law, the IPUC can suspend a filing for an initial period not to exceed five months and an additional extension of 60 days with a showing of good cause.

In California, the CPUC has the authority to suspend proposed new rates, subject to hearing, for a period not to exceed 18 months. The CPUC may extend the suspension period on a case-by-case basis.

Adjustment Mechanisms

In addition to recovery through base rates, PacifiCorp also achieves recovery of certain costs through various adjustment mechanisms as summarized below.

State Regulator	Base Rate Test Period	Adjustment Mechanism
UPSC	Forecasted or historical with known and measurable changes ⁽¹⁾	EBA under which 100% of the difference between base net power costs set during a general rate case and actual net power costs is deferred and reflected in future rates. Wheeling revenue and PTCs are also included in the mechanism with a true-up at 100%. Balancing account to provide for 100% recovery or refund of the difference between the level of REC revenues included in base rates and actual REC revenues after adjusting for a REC incentive authorized by the UPSC. Recovery mechanism for single capital investments that in total exceed 1% of existing rate base when a general rate case has occurred within the preceding 18 months. Wildland Fire Mitigation Balancing Account to recover operating expenses and capital expenditures incurred to implement PacifiCorp's Utah Wildland Fire Protection Plan incremental to those included in base rates.
OPUC	Forecasted	PCAM under which 90% of the difference between forecasted net variable power costs and PTCs established under the annual TAM and actual net variable power costs and PTCs is deferred and reflected in future rates. The difference between the forecasted and actual net variable power costs and PTCs must fall outside of an established asymmetrical deadband, with a negative annual power cost variance deadband of \$15 million; and a positive annual power cost variance deadband of \$30 million and is subject to an earnings test of +/- 1% on PacifiCorp's allowed return on equity. Annual TAM based on forecasted net variable power costs and PTCs. Renewable Adjustment Clause to recover the revenue requirement of new renewable resources and associated transmission costs that are not reflected in general rates. Balancing account for recovery of costs associated with the purchase of RECs necessary to meet Oregon's RPS requirements. Annual Wildfire Mitigation and Vegetation Management Cost Recovery Mechanism to recover vegetation management and wildfire mitigation operations and maintenance costs and wildfire mitigation capital costs, incremental to those included in base rates. Recovery is subject to performance metrics and earnings tests. Wildfire Mitigation Plan Automatic Adjustment Clause was approved to recover the capital and operations and maintenance costs associated with implementation and operation of PacifiCorp's Oregon Wildfire Mitigation Plan.
WPSC	Forecasted or historical with known and measurable changes ⁽¹⁾	ECAM under which 80% of the difference between base net power costs set during a general rate case and actual net power costs is deferred and reflected in future rates. Within the mechanism, chemical costs and start-up fuel costs are also included at the 80% symmetrical sharing band and PTCs are included at 100% symmetrical sharing. REC and SO₂ revenue adjustment mechanism to provide for recovery or refund of 100% of any difference between actual REC and SO₂ revenues and the level in rates.
WUTC	Historical with known and measurable changes	PCAM under which the difference between base net power costs set during a general rate case and actual net power costs is deferred and reflected in future rates after applying a \$4 million deadband for positive or negative net power cost variances. For net power cost variances between \$4 million and \$10 million, amounts to be recovered from customers are allocated 50/50 and amounts to be credited to customers are allocated 75/25 (customers/PacifiCorp). Positive or negative net power cost variances in excess of \$10 million are allocated 90/10 (customers/PacifiCorp). The mechanism includes a true-up of PTCs at 100%.

State Regulator	Base Rate Test Period	Adjustment Mechanism
		Deferral mechanism of costs for up to 24 months of new base load generation resources and eligible renewable resources and related transmission that qualify under the state's emissions performance standard and are not reflected in base rates. REC revenue tracking mechanism to provide credit of 100% of REC revenues to customers. Decoupling mechanism under which the difference between actual annual revenues and authorized revenues per customer per specified rate schedules is deferred and reflected in future rates. To trigger a rate adjustment, the deferral balance must exceed plus or minus 2.5% of the authorized revenue at the end of each deferral period by rate class. Rate adjustments must not exceed a surcharge of 5% of the actual normalized revenue by class.
IPUC	Historical with known and measurable changes	ECAM under which 90% of the difference between base net power costs set during a general rate case and actual net power costs is deferred and reflected in future rates. Also provides for recovery or refund of 100% of the difference between the level of REC revenues included in base rates and actual REC revenues and differences in actual PTCs compared to the amount in base rates.
CPUC	Forecasted	PTAM for major capital additions that allows for rate adjustments outside of the context of a traditional general rate case for the revenue requirement associated with capital additions exceeding \$50 million on a total-company basis. Filed as eligible capital additions are placed into service. ECAC that allows for an annual update to actual and forecasted net power costs. PTAM for attrition, a mechanism that allows for an annual adjustment to costs other than net power costs. Catastrophic Events Memorandum Account for catastrophic events, allows for deferral and cost recovery of reasonable costs incurred as the result of catastrophic events, which are events for which a state or federal agency has declared a state of emergency. Fire Risk Mitigation Memorandum Account to track costs related to wildfire mitigation activities incremental to what is in base rates and Wildfire Mitigation Plan Memorandum Account to track costs associated with the implementation of PacifiCorp's approved wildfire mitigation plan.

- (1) PacifiCorp has relied on both historical test periods with known and measurable adjustments, as well as forecasted test periods.

MidAmerican Energy

Rate Filings

Under Iowa law, a utility may implement temporary rates, without IUC review and subject to refund, on or after 10 days of filing a request for higher base rates. If the IUC has not issued a final order within 10 months after the filing date, the temporary rates become final. Under Illinois law, new base rates may become effective 45 days after the filing of a request with the ICC, or earlier with ICC approval. The ICC has authority to suspend the proposed new rates, subject to hearing, for a period not to exceed approximately 11 months after filing. South Dakota law authorizes the SDPUC to suspend new base rates for up to six months during the pendency of rate proceedings; however, a utility may implement all or a portion of the proposed new rates six months after the filing of a request for a rate increase subject to refund pending a final order in the proceeding.

Iowa law also permits rate-regulated utilities to seek ratemaking principles with the IUC prior to the construction of certain types of new generating facilities. Pursuant to this law, MidAmerican Energy has applied for and obtained IUC ratemaking principles orders for a 484-MW (MidAmerican Energy's share) coal-fueled generating facility, a 495-MW combined cycle natural gas-fueled generating facility and 6,841 MWs (nominal ratings) of wind-powered generating facilities as of December 31, 2024. These ratemaking principles established cost caps for the projects, below which such costs are deemed prudent by the IUC and authorized a fixed rate of return on equity for the respective generating facilities over the regulatory life of the facilities in any future Iowa rate proceeding. As of December 31, 2024, the generating facilities in-service totaled \$7.2 billion, or 32%, of MidAmerican Energy's regulated property, plant and equipment, net and were subject to these ratemaking principles at a weighted average return on equity of 11.3% with a weighted average remaining life of 32 years.

Ratemaking principles for several wind-powered generation projects have established mechanisms in Iowa where electric rate base may be reduced. The current revenue sharing mechanism is in accordance with Wind PRIME ratemaking principles and reduces rate base for Iowa electric returns on equity exceeding an established benchmark. Sharing is triggered by MidAmerican Energy's actual equity return being above a threshold calculated annually. The threshold, not to exceed 11%, is the weighted average equity return of rate base with returns authorized via ratemaking principles proceedings and all other rate base. For all other rate base, the return is based on interest rates on 30-year A-rated utility bond yields plus 400 basis points, with a minimum return of 9.5%. MidAmerican Energy shares with customers 90% of the revenue in excess of the trigger. A second mechanism, the retail customer benefit mechanism, reduces electric rate base for the value of higher cost retail energy displaced by covered wind-powered production and applies to the wind-powered generating facilities constructed under the Wind X and Wind XII projects, and wind-powered generating facilities placed in service in 2023 and future projects yet to be constructed under the Wind PRIME project that was approved by the IUC in December 2023. Rate base reductions under these mechanisms are applied to coal and other generation facilities in specified orders. A third mechanism, the Iowa EAC rate mitigation mechanism, provides EAC rate stability to customers by allocating revenue sharing amounts as required to reduce retail electric energy cost recoveries to a targeted amount.

Adjustment Mechanisms

Under its current Iowa, Illinois and South Dakota electric tariffs, MidAmerican Energy is allowed to recover fluctuations in electric energy costs for its retail electric sales through fuel, or energy, cost adjustment mechanisms. Additionally, MidAmerican Energy has transmission adjustment clauses to recover certain transmission charges related to retail customers in all jurisdictions. The transmission adjustment mechanisms recover costs billed by the MISO for regional transmission service. The Illinois adjustment mechanism additionally recovers MidAmerican Energy's entire transmission revenue requirement attributable to Illinois. The adjustment mechanisms reduce the regulatory lag for the recovery of energy and transmission costs related to retail electric customers in these jurisdictions and accomplish, with limited timing differences, a pass-through of the related costs to these customers. Recoveries through these adjustment mechanisms are reflected in operating revenue, and the related costs are reflected in cost of fuel and energy or operations and maintenance expense, as applicable.

Of the wind-powered generating facilities placed in-service as of December 31, 2024, 5,213 MWs (nominal ratings) have not been included in the determination of MidAmerican Energy's Iowa retail electric base rates. In accordance with related ratemaking principles, until such time as these generation assets are reflected in base rates and ceasing thereafter, MidAmerican Energy will continue to reduce its revenue from Iowa EAC recoveries by \$12 million each calendar year.

MidAmerican Energy's cost of natural gas purchased for resale is collected for each jurisdiction through a uniform PGA, which is updated monthly to reflect changes in actual costs. Subject to prudence reviews, the PGA accomplishes a pass-through of MidAmerican Energy's cost of natural gas purchased for resale to its customers and, accordingly, has no direct effect on net income.

MidAmerican Energy's electric and natural gas energy efficiency program costs are collected through bill riders that are adjusted annually based on actual and expected costs in accordance with the energy efficiency plans filed with and approved by the respective state regulatory commission. As such, the energy efficiency program costs, which are reflected in operations and maintenance expense, and related recoveries, which are reflected in operating revenue, have no direct impact on net income.

MidAmerican Energy has income tax rider mechanisms in Iowa and Illinois that were established in response to significant changes to the Internal Revenue Code enacted in 2017, including, among other things, a reduction in the U.S. federal corporate income tax rate from 35% to 21%. As a result of these changes, MidAmerican Energy re-measured its accumulated deferred income tax balances at the 21% rate and increased regulatory liabilities pursuant to the approved mechanisms. In December 2018, the IUC approved in final form a tax expense revision mechanism that reduces customer electric rates for the impact of the lower income tax rate on current operations, as calculated annually, and defers the amortization of excess accumulated deferred income taxes created by their re-measurement at the 21% income tax rate to a regulatory liability, the disposition of which will be determined in MidAmerican Energy's next rate case. In 2018, Iowa Senate File 2417 was signed into law, with updates made in 2022 with the enactment of Iowa House File 2317, which, among other items, reduced the state of Iowa corporate tax rate in stages from 12% to its current 7.1%, and the impacts of such changes are included in the Iowa tax expense revision mechanism.

Rate Filings

Nevada enacted Assembly Bill 524 ("AB 524") on June 15, 2023. The legislation, among other things, allows an electric utility to file a general rate application more frequently than once every three years. Under AB 524, Nevada statutes require the Nevada Utilities to file electric general rate cases at least every three years with the PUCN and prohibit the Nevada Utilities from filing another general rate application until all pending general rate applications filed have been decided by the Commission unless, after application and hearing, the Commission determines that a substantial financial emergency would exist if the public utility or its affiliate is not permitted to file another general rate case sooner. Sierra Pacific may also file natural gas general rate cases with the PUCN. The Nevada Utilities are also subject to a two-part fuel and purchased power adjustment mechanism. The Nevada Utilities make quarterly filings to reset the BTERs, based on the last 12 months of fuel and purchased power costs. The difference between actual fuel and purchased power costs and the revenue collected in the BTERs is deferred into a balancing account. The DEAA rate clears amounts deferred into the balancing account. Nevada regulations allow an electric or natural gas utility that adjusts its BTERs on a quarterly basis to request PUCN approval to make quarterly changes to its DEAA rate if the request is in the public interest. During required annual DEAA proceedings, the prudence of fuel and purchased power costs is reviewed, and if any costs are disallowed on such grounds, the disallowances will be incorporated into the next quarterly BTERs change. Also, on an annual basis, the Nevada Utilities (a) seek a determination that energy efficiency program expenditures were reasonable, (b) request that the PUCN reset base and amortization EEPR, and (c) request that the PUCN reset base and amortization EEIR.

EEPR and EEIR

EEPR was established to allow the Nevada Utilities to recover the costs of implementing energy efficiency programs and EEIR was established to offset the negative impacts on revenue associated with the successful implementation of energy efficiency programs. These rates change once a year in the utility's annual DEAA application based on energy efficiency program budgets prepared by the Nevada Utilities and approved by the PUCN in the IRP proceedings. When the Nevada Utilities' regulatory earned rate of return for a calendar year exceeds the regulatory rate of return used to set base tariff general rates, they are obligated to refund energy efficiency implementation revenue previously collected for that year.

Net Metering

Nevada enacted Assembly Bill 405 ("AB 405") on June 15, 2017. The legislation, among other things, established net metering crediting rates for private generation customers with installed net metering systems less than 25 kilowatts. Under AB 405, private generation customers will be compensated for excess energy on a monthly basis at 95% of the rate the customer would have paid for a kilowatt-hour of electricity supplied by the Nevada Utilities for the first 80 MWs of cumulative installed capacity of all net metering systems in Nevada, 88% of the rate for the next 80 MWs, 81% of the rate for the next 80 MWs and 75% of the rate for any additional private generation capacity. As of December 31, 2023, the cumulative installed and applied-for capacity of net metering systems under AB 405 in Nevada was 876 MWs.

Natural Disaster Protection Plan ("NDPP")

Senate Bill 329 ("SB 329"), Natural Disaster Mitigation Measures, was signed into law on May 22, 2019. The legislation requires the Nevada Utilities to submit a NDPP to the PUCN. The PUCN adopted NDPP regulations on January 29, 2020, that require the Nevada Utilities to file their NDPP for approval on or before March 1 of every third year. The regulations also require annual updates to be filed on or before September 1 of the second and third years of the plan. The plan must include procedures, protocols and other certain information as it relates to the efforts of the Nevada Utilities to prevent or respond to a fire or other natural disaster. The expenditures incurred by the Nevada Utilities in developing and implementing the NDPP are required to be held in a regulatory asset account, with the Nevada Utilities filing an application for recovery on or before March 1 of each year. The PUCN reopened its investigation and rulemaking on SB 329 and the comment period for the reopened investigation ended in early February 2021. Final regulations were adopted by the PUCN and filed in November 2024.

Federal Regulation

The FERC is an independent agency with broad authority to implement provisions of the Federal Power Act, the Natural Gas Act ("NGA"), the Energy Policy Act of 2005 ("Energy Policy Act") and other federal statutes. The FERC regulates rates for wholesale sales of electricity; transmission of electricity, including pricing and regional planning for the expansion of transmission systems; electric system reliability; utility holding companies; accounting and records retention; securities issuances; construction and operation of hydroelectric facilities; and other matters. The FERC also has the enforcement authority to assess civil penalties of up to \$1.6 million per day per violation of rules, regulations and orders issued under the Federal Power Act. The Utilities have implemented programs and procedures that facilitate and monitor compliance with the FERC's regulations described below. MidAmerican Energy is also subject to regulation by the NRC pursuant to the Atomic Energy Act of 1954, as amended ("Atomic Energy Act"), with respect to its interest in the Quad Cities Station.

Wholesale Electricity and Capacity

The FERC regulates the Utilities' rates charged to wholesale customers for electricity and transmission capacity and related services. Much of the Utilities' wholesale electricity sales and purchases occur under market-based pricing allowed by the FERC and are therefore subject to market volatility. The Utilities are precluded from selling at market-based rates in the PacifiCorp-East, PacifiCorp-West, and Nevada Utilities balancing authority areas. Wholesale electricity sales in those specific balancing authority areas are permitted at cost-based rates. PacifiCorp and the Nevada Utilities have been granted the authority to bid into the California EIM at market-based rates.

The Utilities' authority to sell electricity in wholesale electricity markets at market-based rates is subject to triennial reviews conducted by the FERC. Accordingly, the Utilities are required to submit triennial filings to the FERC that demonstrate a lack of market power over sales of wholesale electricity and electric generation capacity in their respective market areas. PacifiCorp, the Nevada Utilities and certain affiliates, representing the BHE Northwest Companies, file together for market power study purposes. The BHE Northwest Companies' most recent triennial filing was made in June 2022 and was accepted by FERC in an order issued December 23, 2024. MidAmerican Energy and certain affiliates file together for market power study purposes of the FERC-defined Northeast Region. The most recent triennial filing for the Northeast Region was made in June 2023, and it remains under review by the FERC. MidAmerican Energy and certain affiliates file together for market power study purposes of the FERC-defined Central Region. The most recent triennial filing for the Central Region was made in December 2023, and it remains pending under review. Under the FERC's market-based rules, the Utilities must also file with the FERC a notice of change in status when there is a change in the conditions that the FERC relied upon in granting market-based rate authority. MidAmerican Energy filed a notice of non-material change in status in July 2022, and the filing is currently under review by the FERC. In January 2024, MidAmerican Energy filed a change in status filing due to the addition of the Chickasaw wind farm generation, and the filing is currently under review by the FERC.

Transmission

PacifiCorp's and the Nevada Utilities' wholesale transmission services are regulated by the FERC under cost-based regulation subject to PacifiCorp's and the Nevada Utilities' OATTs. These services are offered on a non-discriminatory basis, which means that all potential customers are provided an equal opportunity to access the transmission system. PacifiCorp's and the Nevada Utilities' transmission business is managed and operated independently from its wholesale marketing business in accordance with the FERC's Standards of Conduct. PacifiCorp and the Nevada Utilities have made several required compliance filings in accordance with these rules.

In December 2011, PacifiCorp adopted a cost-based formula rate under its OATT for its transmission services. Cost-based formula rates are intended to be an effective means of recovering PacifiCorp's investments and associated costs of its transmission system without the need to file rate cases with the FERC, although the formula rate results are subject to discovery and challenges by the FERC and intervenors. A significant portion of these services are provided to PacifiCorp's energy supply management function.

MidAmerican Energy participates in the MISO as a transmission-owning member. Accordingly, the MISO is the transmission provider under its FERC-approved OATT. While the MISO is responsible for directing the operation of MidAmerican Energy's transmission system, MidAmerican Energy retains ownership of its transmission assets and, therefore, is subject to the FERC's reliability standards discussed below. MidAmerican Energy's transmission business is managed and operated independently from its wholesale marketing business in accordance with the FERC's Standards of Conduct.

MidAmerican Energy constructed and owns four Multi-Value Projects ("MVPs") located in Iowa and Illinois that added approximately 250 miles of 345-kV transmission line to MidAmerican Energy's transmission system since 2012. The MISO's OATT allows for broad cost allocation for MidAmerican Energy's MVPs, including similar MVPs of other MISO participants. Accordingly, a significant portion of the revenue requirement associated with MidAmerican Energy's MVP investments is shared with other MISO participants based on the MISO's cost allocation methodology, and a portion of the revenue requirement of the other participants' MVPs is allocated to MidAmerican Energy, which MidAmerican Energy recovers from customers via a rider mechanism. The transmission assets and financial results of MidAmerican Energy's MVPs are excluded from the determination of its base retail electric rates.

The FERC has established an extensive number of mandatory reliability standards developed by the NERC and the WECC, including planning and operations, critical infrastructure protection and regional standards. Compliance, enforcement and monitoring oversight of these standards is carried out by the FERC; the NERC; and the WECC for PacifiCorp, Nevada Power, and Sierra Pacific; and the Midwest Reliability Organization for MidAmerican Energy.

Hydroelectric

The FERC licenses and regulates the operation of hydroelectric systems, including license compliance and dam safety programs. Most of PacifiCorp's hydroelectric generating facilities are licensed by the FERC as major systems under the Federal Power Act, and certain of these systems are licensed under the Oregon Hydroelectric Act. Under the Federal Power Act, 16 of PacifiCorp's hydroelectric developments are classified as "high hazard potential," meaning it is probable in the event of a dam failure that loss of human life in the downstream population could occur. PacifiCorp uses the FERC's guidelines to develop public safety programs consisting of a dam safety program and emergency action plans.

For an update regarding PacifiCorp's Klamath River hydroelectric system, refer to Note 16 of the Notes to Consolidated Financial Statements of Berkshire Hathaway Energy in Item 8 of this Form 10-K and Note 14 of the Notes to Consolidated Financial Statements of PacifiCorp in Item 8 of this Form 10-K.

Nuclear Regulatory Commission

General

MidAmerican Energy is subject to the jurisdiction of the NRC with respect to its license and 25% interest in Quad Cities Station. Constellation Energy, the operator and 75% owner of Quad Cities Station, is under contract with MidAmerican Energy to secure and keep in effect all necessary NRC licenses and authorizations.

The NRC regulates the granting of permits and licenses for the construction and operation of nuclear generating stations and regularly inspects such stations for compliance with applicable laws, regulations and license terms. Current licenses for Quad Cities Station provide for operation until December 14, 2032. The NRC review and regulatory process covers, among other things, operations, maintenance, environmental and radiological aspects of such stations. The NRC may modify, suspend or revoke licenses and impose civil penalties for failure to comply with the Atomic Energy Act, the regulations under such Act or the terms of such licenses.

Federal regulations provide that any nuclear operating facility may be required to cease operation if the NRC determines there are deficiencies in state, local or utility emergency preparedness plans relating to such facility, and the deficiencies are not corrected. Constellation Energy has advised MidAmerican Energy that an emergency preparedness plan for Quad Cities Station has been approved by the NRC. Constellation Energy has also advised MidAmerican Energy that state and local plans relating to Quad Cities Station have been approved by the Federal Emergency Management Agency.

The NRC also regulates the decommissioning of nuclear-powered generating facilities, including the planning and funding for the eventual decommissioning of the facilities. In accordance with these regulations, MidAmerican Energy submits a biennial report to the NRC providing reasonable assurance that funds will be available to pay its share of the costs of decommissioning Quad Cities Station. MidAmerican Energy has established a trust for the investment of funds collected for nuclear decommissioning of Quad Cities Station.

Under the Nuclear Waste Policy Act of 1982 ("NWPAA"), the DOE is responsible for the selection and development of repositories for, and the permanent disposal of, spent nuclear fuel and high-level radioactive wastes. Constellation Energy, as required by the NWPAA, signed a contract with the DOE under which the DOE was to receive spent nuclear fuel and high-level radioactive waste for disposal beginning not later than January 1998. The DOE did not begin receiving spent nuclear fuel on the scheduled date and remains unable to receive such fuel and waste. The costs to be incurred by the DOE for disposal activities were previously being financed by fees charged to owners and generators of the waste. In accordance with a 2013 ruling by the D.C. Circuit, the DOE, in May 2014, provided notice that, effective May 16, 2014, the spent nuclear fuel disposal fee would be zero. In 2004, Constellation Energy, reached a settlement with the DOE concerning the DOE's failure to begin accepting spent nuclear fuel in 1998. As a result, Quad Cities Station has been billing the DOE, and the DOE is obligated to reimburse the station for all station costs incurred due to the DOE's delay. Constellation Energy has constructed an interim spent fuel storage installation ("ISFSI") at Quad Cities Station consisting of two pads to store spent nuclear fuel in dry casks to free space in the storage pool. The first dry cask was placed in-service in 2005. As of December 31, 2021, the first pad at the ISFSI is full, and the second pad is in operation. The first and second pads at the ISFSI are expected to facilitate storage of casks to support operations at Quad Cities Station through the end of its current operating licenses, which is 2032.

Nuclear Insurance

MidAmerican Energy maintains financial protection against catastrophic loss associated with its interest in Quad Cities Station through a combination of insurance purchased by Constellation Energy, insurance purchased directly by MidAmerican Energy, and the mandatory industry-wide loss funding mechanism afforded under the Price-Anderson Amendments Act of 1988 ("Price-Anderson"), which was amended and extended by the Energy Policy Act. The general types of coverage maintained are: nuclear liability, property damage or loss and nuclear worker liability, as discussed below.

Constellation Energy purchases private market nuclear liability insurance for Quad Cities Station in the maximum available amount of \$500 million, which includes coverage for MidAmerican Energy's ownership. In accordance with Price-Anderson, excess liability protection above that amount is provided by a mandatory industry-wide Secondary Financial Protection program under which the licensees of nuclear generating facilities could be assessed for liability incurred due to a serious nuclear incident at any commercial nuclear reactor in the U.S. Currently, MidAmerican Energy's aggregate maximum potential share of an assessment for Quad Cities Station is approximately \$25 million per incident, payable in installments not to exceed \$12 million annually.

The insurance for nuclear property damage losses covers property damage, stabilization and decontamination of the facility, disposal of the decontaminated material and premature decommissioning arising out of a covered loss. For Quad Cities Station, Constellation Energy purchases primary property insurance protection for the combined interests in Quad Cities Station, with coverage limits for nuclear damage losses up to \$1.5 billion for nuclear perils and \$500 million for non-nuclear perils. MidAmerican Energy also directly purchases extra expense coverage for its share of replacement power and other extra expenses in the event of a covered accidental outage at Quad Cities Station. The property and related coverages purchased directly by MidAmerican Energy and by Constellation Energy, which includes the interests of MidAmerican Energy, are underwritten by an industry mutual insurance company and contain provisions for retrospective premium assessments to be called upon based on the industry mutual board of directors' discretion for adverse loss experience. Currently, the maximum retrospective amounts that could be assessed against MidAmerican Energy from industry mutual policies for its obligations associated with Quad Cities Station total \$9 million.

The master nuclear worker liability coverage, which is purchased by Constellation Energy for Quad Cities Station, is an industry-wide guaranteed-cost policy with an aggregate limit of \$500 million for the nuclear industry as a whole, which is in effect to cover tort claims of workers in nuclear-related industries.

U.S. Mine Safety

PacifiCorp's surface mining operations are regulated by the Federal Mine Safety and Health Administration, which administers federal mine safety and health laws and regulations, and state regulatory agencies. The Federal Mine Safety and Health Administration has the statutory authority to institute a civil action for relief, including a temporary or permanent injunction, restraining order or other appropriate order against a mine operator who fails to pay penalties or fines for violations of federal mine safety standards. Information regarding PacifiCorp's mine safety violations and other legal matters disclosed in accordance with Section 1503(a) of the Dodd-Frank Reform Act is included in Exhibit 95 to this Form 10-K.

Interstate Natural Gas Pipeline Subsidiaries

The Pipeline Companies are regulated by the FERC, pursuant to the NGA and the Natural Gas Policy Act of 1978. Under this authority, the FERC regulates, among other items, (a) rates, charges, terms and conditions of service, (b) the construction and operation of interstate pipelines, storage and related facilities, including the extension, expansion or abandonment of such facilities and (c) the construction and operation of LNG export/import facilities. The Pipeline Companies hold certificates of public convenience and necessity and LNG facility authorizations issued by the FERC, which authorize them to construct, operate and maintain their pipeline and related facilities and services.

In February 2022, the FERC updated its certificate policy that guides the authorization of natural gas projects and issued an interim policy providing guidance on how the FERC will review a natural gas project for its impact on climate change. The policies apply to pending and future natural gas projects. On March 24, 2022, the FERC revoked application of the policies and sought further comments.

FERC regulations and the Pipeline Companies' tariffs allow each of the Pipeline Companies to charge approved rates for the services set forth in their respective tariffs. Generally, these rates are a function of the cost of providing services to customers, including prudently incurred operations and maintenance expenses, taxes, depreciation and amortization and a reasonable return on invested capital. Tariff rates for each of the Pipeline Companies have been developed under a rate design methodology whereby substantially all fixed costs, including a return on invested capital and income taxes, are collected through reservation charges, which are paid by firm transportation and storage customers regardless of volumes shipped. Commodity charges, which are paid only with respect to volumes actually shipped, are designed to recover the remaining, primarily variable, costs. Kern River's reservation rates have historically been approved using a "levelized" cost-of-service methodology so that the rate remains constant over the levelization period. This levelized cost of service has been achieved by using a FERC-approved depreciation schedule in which depreciation increases as the cost of capital decreases on declining rate base. Each of the Pipeline Companies also hold authority to negotiate rates for their services, subject to requirements to offer cost-based rate alternatives, and to publish such negotiated rates. In addition, for services that are not subject to FERC rate jurisdiction pursuant to Section 3 of the Natural Gas Act, Cove Point charges rates that are established by contract.

The Pipeline Companies' rates are subject to change in future general rate proceedings. Rates for natural gas pipelines are changed by filings under either Section 5 or Section 4 of the Natural Gas Act. Section 5 proceedings are initiated by the FERC or the pipeline's customers for a potential reduction to rates that the FERC finds are no longer just and reasonable. In a Section 5 proceeding, the initiating party has the burden of demonstrating that the currently effective rates of the pipeline are no longer just and reasonable, and of demonstrating alternative just and reasonable rates. Any rate decrease as a result of a Section 5 proceeding is implemented prospectively upon the issuance of a final FERC order adopting the new just and reasonable rates. Section 4 rate proceedings are initiated by the natural gas pipeline, who must demonstrate that the new proposed rates are just and reasonable. The new rates as a result of a Section 4 proceeding are typically implemented six months after the Section 4 filing if higher than prior rates and are subject to refund upon issuance of a final order by the FERC.

The FERC-regulated natural gas companies may not grant undue preference to any customer. FERC regulations require that certain information be made public for market access, through standardized internet websites. These regulations also restrict each pipeline's marketing affiliates' access to certain non-public information that could affect price or availability of service.

Interstate natural gas pipelines are also subject to regulations administered by the Office of Pipeline Safety within the Pipeline and Hazardous Materials Safety Administration, an agency of the DOT. Federal pipeline safety regulations are issued pursuant to the Natural Gas Pipeline Safety Act of 1968, as amended ("NGPSA"), which establishes safety requirements in the design, construction, operation and maintenance of interstate natural gas facilities, and requires an entity that owns or operates pipeline facilities to comply with such plans. Major amendments to the NGPSA include the Pipeline Safety Improvement Act of 2002 ("2002 Act"), the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 ("2006 Act"), the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 ("2011 Act") the Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2016 ("2016 Act") and the Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2020 ("2020 Act").

The 2002 Act established additional safety and pipeline integrity regulations for all natural gas pipelines in high-consequence areas. The 2002 Act imposed major new requirements in the areas of operator qualifications, risk analysis and integrity management. The 2002 Act mandated more frequent periodic inspection or testing of natural gas pipelines in high-consequence areas, which are locations where the potential consequences of a natural gas pipeline accident may be significant or may do considerable harm to persons or property. Pursuant to the 2002 Act, the DOT promulgated regulations that require natural gas pipeline operators to develop comprehensive integrity management programs, to identify applicable threats to natural gas pipeline segments that could impact high-consequence areas, to assess these segments and to provide ongoing mitigation and monitoring. The regulations require recurring inspections of high-consequence area segments every seven years after the initial baseline assessment.

The 2006 Act required pipeline operators to institute human factors management plans for personnel employed in pipeline control centers. DOT regulations published pursuant to the 2006 Act required development and implementation of written control room management procedures.

The 2011 Act was a response to natural gas pipeline incidents, most notably the San Bruno natural gas pipeline explosion that occurred in September 2010 in California. The 2011 Act increased the maximum allowable civil penalties for violations, directs operator assistance for Federal authorities conducting investigations and authorized the DOT to hire additional inspection and enforcement personnel. The 2011 Act also directed the DOT to study several topics, including the definition of high-consequence areas, the use of automatic shutoff valves in high-consequence areas, expansion of integrity management requirements beyond high-consequence areas and cast iron pipe replacement. The studies are complete, and a number of notices of proposed rulemaking have been issued. The Pipeline and Hazardous Materials Safety Administration ("PHMSA") issued the Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements and Other Related Amendments final rule in October 2019. The primary change was the expansion of the pipeline integrity assessment requirements to cover moderate-consequence areas and reconfirming maximum allowable operating pressures. Pipeline operators were required to develop procedures to address assessment requirements by July 2021 and complete 50% of the required MAOP reconfirmation actions by 2028 and the remaining by 2035. The BHE Pipeline Group has updated procedures, identified pipeline segments subject to the rule and has planned projects to complete required assessments. PHMSA sent Part 2 of the rule to the Federal Register for publishing August 4, 2022, and it was published in the Federal Register August 24, 2022. The rule initially had an effective date of May 2023, but has been extended to February 2024. The third part of the rule, the gas gathering rule, has also been issued, but has minimal impact on the BHE Pipeline Group.

The 2016 Act required the Pipeline and Hazardous Materials Safety Administration to set federal minimum safety standards for underground natural gas storage facilities and authorized emergency order authority. In February 2020, the Pipeline and Hazardous Materials Safety Administration issued a final rule regarding underground natural gas storage facilities that incorporates by reference the American Petroleum Institute's Recommended Practice 1171, "Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs," clarifies certain aspects of the mandatory nature of the standard and defines regulatory completion dates for underground storage facility risk assessments. The BHE Pipeline Group has 20 total underground natural gas storage fields at EGTS and Northern Natural Gas that fall under this regulation and is complying with the final rule. The BHE Pipeline Group underground storage fields have had several audits under the Final Rule with no notices of probable violations issued. Kern River, Carolina Gas and Cove Point do not have underground natural gas storage facilities.

The 2020 Act required operations to review and update their inspection and maintenance plans to address how the plans contribute to eliminate hazardous leaks of natural gas, reduction of fugitive emissions and replacement or remediation of pipelines that are known to leak based on the material, design or past operating maintenance history. BHE Pipeline Group has completed the review and update of its inspection and maintenance plans. To assist in this effort, Kern River participated in a non-punitive pilot inspection with the Pipeline and Hazardous Materials Safety Administration.

The DOT and related state agencies routinely audit and inspect the pipeline facilities for compliance with their regulations. The Pipeline Companies conduct periodic internal audits of their facilities with more frequent reviews of those deemed higher risk. The Pipeline Companies also conduct preliminary audits in advance of agency audits. Compliance issues that arise during these audits or during the normal course of business are addressed on a timely basis. The Pipeline Companies believe their pipeline systems comply in all material respects with the NGPSA and with DOT regulations issued pursuant to the NGPSA.

Northern Powergrid Distribution Companies

The Northern Powergrid Distribution Companies, as holders of electricity distribution licenses, are subject to regulation by GEMA. GEMA regulates distribution network operators ("DNOs") within the terms of the Electricity Act 1989 and the terms of DNO licenses, which are revocable with 25 years notice. Under the Electricity Act 1989, GEMA has a duty to ensure that DNOs can finance their regulated activities and DNOs have a duty to maintain an investment grade credit rating. GEMA discharges certain of its duties through its staff within Ofgem. Each of fourteen licensed DNOs distributes electricity from the national grid transmission system and distribution-connected generators to end users within its respective distribution services area.

DNOs are subject to price controls, enforced by Ofgem, that limit the revenue that may be recovered and retained from their electricity distribution activities. The regulatory regime that has been applied to electricity distributors in Great Britain encourages companies to look for efficiency gains in order to improve profits. The distribution price control formula also adjusts the revenue received by DNOs to reflect a number of factors, including, but not limited to, the rate of inflation (as measured by the United Kingdom's Retail Prices Index) and the quality of service delivered by the licensee's distribution system. The current price control, Electricity Distribution 2 ("ED2"), has been set for a period of five years, starting April 1, 2023. The procedure and methodology adopted at a price control review are at the reasonable discretion of Ofgem. Ofgem's judgment of the future allowed revenue of licensees is likely to take into account, among other things:

- the actual operating and capital costs of each of the licensees;
- the operating and capital costs that each of the licensees would incur if it were as efficient as, in Ofgem's judgment, the more efficient licensees;
- the actual value of certain costs which are judged to be beyond the control of the licensees;
- the taxes that each licensee is expected to pay;
- the regulatory value ascribed to the expenditures that have been incurred in the past and the efficient expenditures that are to be incurred in the forthcoming regulatory period;
- the rate of return to be allowed on expenditures that make up the regulatory asset value;
- the financial ratios of each of the licensees and the license requirement for each licensee to maintain investment grade status;
- an allowance in respect of the repair of the pension deficits in the defined benefit pension schemes sponsored by each of the licensees; and
- any under- or over-recoveries of revenues, relative to allowed revenues, in the previous price control period.

A number of incentive schemes also operate within the current price control period to encourage DNOs to provide an appropriate quality of service to end users. This includes specified payments to be made for failures to meet prescribed standards of service. The aggregate of these guaranteed standards payments is uncapped but may be excused in certain prescribed circumstances that are generally beyond the control of the DNOs.

The current electricity distribution price control became effective April 1, 2023 and is due to terminate on March 31, 2028, and will be immediately replaced with a new price control. Although it has been the convention in Great Britain for regulators to conduct periodic regulatory reviews before making proposals for any changes to the price controls, a new price control can be implemented by GEMA without the consent of the DNOs. If a licensee disagrees with a change to its license, it can appeal the matter to the United Kingdom's CMA, as can certain other parties. Any appeals must be notified within 20 working days of the license modification by GEMA. If the CMA determines that the appellant has relevant standing, then the statute requires that the CMA complete its process within six months, or in some exceptional circumstances seven months. The Northern Powergrid Distribution Companies appealed Ofgem's proposals for the resetting of the formula that commenced April 1, 2023, the CMA remitted the matter back to Ofgem to determine and implement a remedy.

Ofgem completed the price control review that resulted in a new price control effective April 1, 2023. The license modifications that give effect to the price control were published by Ofgem on February 3, 2023 and were subject to appeal to the CMA, if an appeal is filed by March 3, 2023. Many aspects of the prior price control were maintained and the changes made generally follow the template that was set by the price controls implemented in April 2021 for transmission and gas distribution in Great Britain. Specific changes include new service standard incentives and mechanisms to adjust cost allowances in specific circumstances, particularly related to investment required to support decarbonization efforts, and partially updating the allowed return on equity within the period for changes in the interest rate on government bonds. Ofgem's final determinations also included an allowed cost of equity of 5.23% plus inflation (calculated using the United Kingdom's consumer prices index including owner occupiers' housing costs) and cost allowances representing a 20% real-term increase compared to the current regulatory period annual average. The base allowed revenue, excluding the effects of incentive schemes, pass-through costs and any deferred revenues from the prior price control, will decrease approximately 4.0% at Northern Powergrid (Northeast) plc and will increase approximately 2.5% at Northern Powergrid (Yorkshire) plc, respectively, in 2023-24 before the addition of inflation.

Ofgem also monitors DNO compliance with license conditions and enforces the remedies resulting from any breach of condition. License conditions include the prices and terms of service, financial strength of the DNO, the provision of information to Ofgem and the public, as well as maintaining transparency, non-discrimination and avoidance of cross-subsidy in the provision of such services. Ofgem also monitors and enforces certain duties of a DNO set out in the Electricity Act 1989, including the duty to develop and maintain an efficient, coordinated and economical system of electricity distribution. Under changes to the Electricity Act 1989 introduced by the Utilities Act 2000, GEMA is able to impose financial penalties on DNOs that contravene any of their license duties or certain of their duties under the Electricity Act 1989, as amended, or that are failing to achieve a satisfactory performance in relation to the individual standards prescribed by GEMA. Any penalty imposed must be reasonable and may not exceed 10% of the licensee's revenue.

AltaLink

AltaLink is regulated by the AUC, pursuant to the *Electric Utilities Act* (Alberta), the *Public Utilities Act* (Alberta), the *Alberta Utilities Commission Act* (Alberta) and the *Hydro and Electric Energy Act* (Alberta). The AUC is an independent, quasi-judicial agency established by the province of Alberta, Canada, which is responsible for, among other things, approving the tariffs of transmission facility owners, including AltaLink, acquisitions of such transmission facility owners or utilities, and construction and operation of new transmission projects in Alberta. The AUC also investigates and rules on regulated rate disputes and system access. The AUC regulates and oversees Alberta's electricity transmission sector with broad authority that may impact many of AltaLink's activities, including its tariffs, rates, construction, operations and financing.

The AUC has various core functions in regulating the Alberta electricity transmission sector, including the following:

- regulating and adjudicating issues related to the operation of electric utilities within Alberta;
- processing and approving general tariff applications relating to revenue requirements, capital expenditure prudence and rates of return including deemed capital structure for regulated utilities while ensuring that utility rates are just and reasonable, and approval of the transmission tariff rates of regulated transmission providers paid by the AESO, which is the independent transmission system operator in Alberta, Canada that controls the operation of AltaLink's transmission system;
- approving the need for new electricity transmission facilities and permits to build and licenses to operate electricity transmission facilities;
- reviewing operations and accounts from electric utilities and conducting on-site inspections to ensure compliance with industry regulation and standards;
- adjudicating enforcement issues including the imposition of administrative penalties that arise when market participants violate the rules of the AESO; and
- collecting, storing, analyzing, appraising and disseminating information to effectively fulfill its duties as an industry regulator.

In addition, AUC approval is required in connection with new energy and regulated utility initiatives in Alberta, amendments to existing approvals and financing proposals by designated utilities.

AltaLink's tariffs are regulated by the AUC under the provisions of the *Electric Utilities Act* (Alberta) in respect of rates and terms and conditions of service. *The Electric Utilities Act* (Alberta) and related regulations require the AUC to consider that it is in the public interest to provide consumers the benefit of unconstrained transmission access to competitive generation and the wholesale electricity market. In regulating transmission tariffs, the AUC must facilitate sufficient investment to ensure the timely upgrade, enhancement or expansion of transmission facilities, and foster a stable investment climate and a continued stream of capital investment for the transmission system.

Under the *Electric Utilities Act* (Alberta), AltaLink prepares and files applications with the AUC for approval of tariffs to be paid by the AESO for the use of its transmission facilities, and the terms and conditions governing the use of those facilities. The AUC reviews and approves such tariff applications based on a cost-of-service regulatory model under a forward test year basis. Under this model, the AUC provides AltaLink with a reasonable opportunity to (i) earn a fair return on equity; and (ii) recover its forecast costs, including operating expenses, depreciation, borrowing costs and taxes (including deemed income taxes) associated with its regulated transmission business. The AUC must approve tariffs that are just, reasonable and not unduly preferential, arbitrary or unjustly discriminatory. AltaLink's transmission tariffs are not dependent on the price or volume of electricity transported through its transmission system.

The AESO is an independent system operator in Alberta, Canada that oversees the Alberta Interconnected Electric System ("AIES") and wholesale electricity market. The AESO is responsible for directing the safe, reliable and economic operation of the AIES, including long-term transmission system planning. AltaLink and the other transmission facility owners receive substantially all of their transmission tariff revenues from the AESO. The AESO, in turn, charges wholesale tariffs, approved by the AUC, in a manner that promotes fair and open access to the AIES and facilitates a competitive market for the purchase and sale of electricity. The AESO monitors compliance with approved reliability standards, which are enforced by the Market Surveillance Administrator, which may impose penalties on transmission facility owners for non-compliance with the approved reliability standards.

The AESO determines the need and plans for the expansion and enhancement of the transmission system in Alberta in accordance with applicable law and reliability standards. The AESO's responsibilities include long-term transmission planning and management, including assessing the current and future transmission system capacity needs of market participants. When the AESO determines an expansion or enhancement of the transmission system is needed, with limited exceptions, it submits an application to the AUC for approval of the proposed expansion or enhancement. The AESO then determines which transmission provider should submit an application to the AUC for a permit and license to construct and operate the designated transmission facilities. Generally, the transmission provider operating in the geographic area where the transmission facilities expansion or enhancement is to be located is selected by the AESO to build, own and operate the transmission facilities. In addition, Alberta law provides that certain transmission projects may be subject to a competitive process open to qualified bidders.

Independent Power Projects

The Yuma, Cordova, Saranac, Power Resources, Topaz, Agua Caliente, Solar Star 1, Solar Star 2, Bishop Hill II, Jumbo Road, Marshall, Grande Prairie, Walnut Ridge, Pinyon Pines I, Pinyon Pines II, Santa Rita, Independence, Fluvanna II, Flat Top, Mariah del Norte, Alamo 6 and Pearl independent power projects are Exempt Wholesale Generators ("EWGs") under the Energy Policy Act, while the Community Solar Gardens, Imperial Valley and Wailuku independent power projects are currently each certified as a Qualifying Facility ("QF") under the Public Utility Regulatory Policies Act of 1978. Both EWGs and QFs generally are exempt from compliance with extensive federal and state regulations that control the financial structure of an electric generating plant and the prices and terms at which electricity may be sold by the facilities.

The Yuma, Cordova, Saranac, Imperial Valley, Topaz, Agua Caliente, Solar Star 1, Solar Star 2, Bishop Hill II, Marshall, Grande Prairie, Walnut Ridge, Independence, Pinyon Pines I and Pinyon Pines II independent power projects have obtained authority from the FERC to sell their power at market-based rates. This authority to sell electricity in wholesale electricity markets at market-based rates is subject to triennial reviews conducted by the FERC. Accordingly, the respective independent power projects are required to submit triennial filings to the FERC that demonstrate a lack of market power over sales of wholesale electricity and electric generation capacity in their respective market areas. The Pinyon Pines I, Pinyon Pines II, Solar Star 1, Solar Star 2, Topaz and Yuma independent power projects and power marketers CalEnergy, LLC and BHER Market Operations, LLC file together for market power study purposes of the FERC-defined Southwest Region. The most recent triennial filing for the Southwest Region was made in June 2022, was supplemented in August 2024, and is awaiting FERC action. The Cordova and Saranac independent power projects and power marketer CalEnergy, LLC file together with MidAmerican Energy and certain affiliates for market power study purposes of the FERC-defined Northeast Region. The most recent triennial filing for the Northeast Region was made in June 2023 and is awaiting FERC action. The Bishop Hill II and Walnut Ridge independent power projects and power marketer CalEnergy, LLC file together with MidAmerican Energy and certain affiliates for market power study purposes of the FERC-defined Central Region. The most recent triennial filing for the Central Region was made in December 2023 and is awaiting FERC action. The Marshall and Grande Prairie independent power projects and power marketer CalEnergy, LLC file together for market power study purposes in the FERC-defined Southwest Power Pool Region. The most recent triennial filing for the Southwest Power Pool Region was made in December 2024 and is awaiting FERC action. Power marketers CalEnergy LLC and BHER Market Operations, LLC also file for market power study purposes in the FERC-defined Northwest Region together with PacifiCorp, Nevada Power Company, Sierra Power Company and certain affiliates. The most recent triennial filing for the Northwest Region was made in June 2022, was supplemented in December 2022, was amended in May 2023, was further supplemented in June 2024 and is awaiting FERC action.

The entire output of Jumbo Road, Santa Rita, Fluvanna II, Flat Top, Mariah del Norte, Alamo 6, Pearl and Power Resources is within ERCOT and market-based authority is not required for such sales solely within ERCOT as the ERCOT market is not a FERC-jurisdictional market. Similarly, Wailuku sells its output solely to the Hawaii Electric Light Company within the Hawaii electric grid, which is not a FERC-jurisdictional market and therefore, Wailuku does not require market-based rate authority.

EWGs are permitted to sell capacity and electricity only in the wholesale markets, not to end users. Additionally, utilities are required to purchase electricity produced by QFs at a price that does not exceed the purchasing utility's "avoided cost" and to sell back-up power to the QFs on a non-discriminatory basis, unless they have successfully petitioned the FERC for an exemption from this purchase requirement. Avoided cost is defined generally as the price at which the utility could purchase or produce the same amount of power from sources other than the QF on a long-term basis. The Energy Policy Act eliminated the purchase requirement for utilities with respect to new contracts under certain conditions. New QF contracts are also subject to FERC rate filing requirements, unlike QF contracts entered into prior to the Energy Policy Act. FERC regulations also permit QFs and utilities to negotiate agreements for utility purchases of power at rates other than the utility's avoided cost.

Residential Real Estate Brokerage Company

HomeServices and its operating subsidiaries are regulated by the U.S. Consumer Financial Protection Bureau which enforces the Truth In Lending Act ("TILA"), the Equal Credit Opportunity Act ("ECOA") and the Real Estate Settlement Procedures Act ("RESPA"); by the U.S. Federal Trade Commission with respect to certain franchising activities; by the U.S. Department of Housing and Urban Development, which enforces the Fair Housing Act ("FHA"); and by state agencies where its subsidiaries operate. TILA and ECOA regulate lending practices. FHA prohibits housing-related discrimination on the basis of race, color, national origin, religion, sex, familial status, and disability. RESPA regulates real estate settlement services including real estate closing practices, lender servicing and escrow account practices and business relationships among settlement service providers and third parties to the transaction.

REGULATORY MATTERS

In addition to the discussion contained herein regarding regulatory matters, refer to "General Regulation" in Item 1 of this Form 10-K for further information regarding the general regulatory framework.

PacifiCorp

Utah

In May 2024, PacifiCorp filed its EBA application to recover deferred net power costs from 2023. The filing requested an increase of \$280 million to what is currently in rates, which PacifiCorp proposed to recover over a two-year period with interest, resulting in a first-year rate increase of \$52 million, or 2.4%, effective on an interim basis July 1, 2024. In June 2024, the UPSC approved an interim rate change effective July 1, 2024. As part of the interim rate change, the UPSC rejected PacifiCorp's proposal to recover the incremental costs over two years, resulting in a rate increase of \$256 million, or 11.6%. A final order from the UPSC is expected in February 2025.

In June 2024, PacifiCorp filed a general rate case requesting a rate increase of \$667 million over two years. The request sought an increase of \$382 million, or 16.2%, effective February 28, 2025, and a second increase of \$285 million, or 12.1%, effective January 1, 2026. The request included increased net power costs, capital investments in transmission and wind-powered generating facilities and higher insurance premiums for third-party liability coverage. In August 2024, PacifiCorp filed an amended application that removed the second rate increase that was associated with net power costs and updated costs associated with insurance premiums. The amended filing requested a rate increase of \$394 million, or 16.7%, effective February 23, 2025. In October 2024, in response to dispositive motions filed by intervenors, the UPSC ordered that the test period costs associated with insurance premiums and wildfire mitigation be removed from the general rate case and consolidated into the separate existing dockets – the insurance premium deferral proceeding and the approval of the wildfire mitigation plan, respectively. The UPSC required that the parties meet to determine "placeholder" amounts for these items in the general rate case pending final decisions in the other proceedings. While PacifiCorp filed an objection to the decision in October 2024, the UPSC subsequently affirmed the order to move the insurance premium and wildfire mitigation items to each pre-existing docket and sought feedback regarding consolidated hearings for the pre-existing dockets and the general rate case. In November 2024, the UPSC issued an order adopting an alternative process to consolidate the general rate case, insurance premium deferral and wildfire mitigation dockets into one with a resolution expected for all matters by April 25, 2025. In November and December 2024, PacifiCorp filed updated testimony that resulted in a revised requested rate increase of \$330 million, or 14.0%.

Oregon

In July 2021, in accordance with the OPUC's December 2020 general rate case order, PacifiCorp filed an application with the OPUC to initiate the review of PacifiCorp's estimated decommissioning and other closure costs per third-party studies associated with its coal-fueled generating facilities. The application requested an initial rate increase of \$35 million, or 2.8%, to become effective January 1, 2022, to recover the incremental costs from those approved in the last general rate case. In November 2022, an independent evaluator was selected. In November 2024, the independent evaluator completed its work reviewing the third-party studies that contain the estimated decommissioning and other closure costs and submitted its report to the OPUC. As part of the general rate case order issued in December 2024 described below, the OPUC adopted the cost estimates for certain coal-fueled generating units per the third-party studies to be recovered over a 12-year period.

In February 2024, PacifiCorp filed a general rate case requesting a rate increase of \$322 million, or 17.9%, to become effective January 1, 2025. The request included new capital investments in transmission and wind-powered generating facilities, higher insurance premiums for third-party liability coverage and proposed funding for a catastrophic fire fund. In July 2024, PacifiCorp filed updated testimony that removed the proposed funding for a catastrophic fire fund and included a reduction in the requested return on equity. As a result of the updates, the requested rate increase was revised to \$214 million, or 11.9%. In August 2024, PacifiCorp filed updated testimony in which the requested rate increase was revised to \$208 million, or 11.2%. Hearings were held in September 2024 and in December 2024, the OPUC issued an order in the general rate case that resulted in a rate increase of \$140 million, or 7.5%, effective January 1, 2025. The order imposed a partial disallowance for a portion of Oregon's share of wildfire mitigation investments, a limited return on PacifiCorp's investment in its 416-mile, 500-kV high voltage transmission line that was placed in-service in 2024 and provides for limited recovery of incremental decommissioning costs associated with PacifiCorp's coal-fueled generating facilities to certain units as described above, recovery of a certain level of third-party liability insurance premiums and a reduction in the return on equity of proposed by PacifiCorp. In February 2025, PacifiCorp filed an application for reconsideration or rehearing with the OPUC regarding the level of recovery provided for Oregon's share of wildfire mitigation investments and PacifiCorp's return on investment in its 416-mile, 500-kV high voltage transmission line set forth in the December 2024 general rate case order.

In February 2024, PacifiCorp filed its TAM requesting approval to update net power costs for 2025. The filing requested a rate decrease of \$18 million, or 1.0%, subject to updates throughout the course of the proceeding, to become effective January 1, 2025. In July 2024, a joint stipulation and supporting testimony was filed settling all issues. Concurrent with the stipulation, PacifiCorp filed its TAM reply update, which reflected a total rate decrease of \$23 million, or 1.3%, subject to final net power cost updates in November 2024. The OPUC approved the joint stipulation in September 2024. The final update, filed in November 2024, resulted in a rate decrease of \$50 million, or 2.8%, effective January 1, 2025.

In May 2024, PacifiCorp filed its 2023 PCAM requesting recovery of the difference between actual net power costs and base net power costs established in the 2023 TAM. The filing requested recovery of \$122 million, which PacifiCorp proposed to recover over a two-year period with interest, resulting in a rate increase of \$64 million, or 3.5%, effective October 1, 2024. In October 2024, a joint stipulation and supporting joint brief was filed settling all issues. Under the stipulation, PacifiCorp would recover \$118 million over a two-year period with interest, resulting in a non-residential rate increase of \$37 million, or 2.0%, effective December 1, 2024, and a residential rate increase of \$26 million, or 1.4%, effective April 1, 2025. In November 2024, the OPUC approved the stipulation, and the non-residential rate increase went into effect on December 1, 2024.

Wyoming

In March 2023, PacifiCorp filed a general rate case requesting a rate increase of \$140 million, or 21.6%, to become effective January 1, 2024. The requested rate increase included recovery of increases in net power costs and new major capital investments in transmission and wind-powered generating facilities. In September 2023, PacifiCorp filed updated testimony that included updated net power costs and increased insurance premium costs associated with third-party liability coverage. In November 2023, the WPSC approved a rate increase of \$54 million, or 8.3%, effective January 1, 2024. The approved rate increase reflected a reduction in the requested return on equity compared to what was sought by PacifiCorp, the exclusion of the increased insurance premium costs and a reduction in net power costs determined by the WPSC. The WPSC's reduction in net power costs reflected the exclusion of the costs associated with the Washington Cap and Invest program. In January 2024, PacifiCorp filed an application for rehearing requesting the WPSC consider three items, including the WPSC's net power costs adjustment, costs associated with the Washington Cap and Invest program and the opportunity to revise PacifiCorp's initial revenue requirement request for updates, corrections and revisions reflected in rebuttal testimony. In April 2024, the WPSC denied a rehearing in an open meeting, and PacifiCorp is pursuing review of this decision in federal and state courts in Wyoming.

In April 2024, PacifiCorp filed its ECAM and its REC and SO₂ revenue adjustment mechanism to recover deferred net power costs from 2023. The combined filing requested a rate increase of \$86 million, or 12.3%, to be effective on an interim basis on July 1, 2024. In June 2024, PacifiCorp updated the filing to reduce the amount of deferred net power costs included in the request by \$2 million. In July 2024, the WPSC approved an interim rate increase of \$84 million, or 11.9%, effective July 1, 2024. In December 2024, the WPSC approved an all-party settlement that resulted in a rate decrease of \$3 million from the interim rates that were previously approved in July 2024. The new rates went into effect January 1, 2025.

In August 2024, PacifiCorp filed a general rate case requesting a rate increase of \$124 million, or 14.7%, to become effective June 1, 2025. The request included new capital investments in transmission and wind-powered generating facilities, a new insurance cost adjustment mechanism and proposed adjustments to the energy cost adjustment mechanism. In January 2025, PacifiCorp filed updated testimony that reduced the requested rate increase to \$110 million, or 13.1%.

Washington

In March 2023, PacifiCorp filed a general rate case requesting a two-year rate plan with a rate increase that included recovery of increases in net power costs and new major capital investments in transmission and wind-powered generating facilities. In October 2023, PacifiCorp filed updated testimony that included updated net power costs, increased insurance premium costs and removal of some capital projects. In December 2023, a multi-party settlement stipulation was filed to update the requested rate increase to \$14 million, or 3.4%, to become effective March 19, 2024, and \$21 million, or 5.0%, to become effective March 1, 2025. A hearing on the settlement stipulation was held in January 2024, and the WUTC accepted the stipulation on March 19, 2024. PacifiCorp submitted the required compliance filings with an updated net power cost forecast, resulting in a rate increase of \$11 million, or 2.7%, effective April 3, 2024. A subsequent compliance filing will be submitted during the first quarter of 2025 for the second year of the two-year rate plan, with rates effective April 3, 2025.

As part of the stipulation in the general rate case, PacifiCorp agreed to file a review and potential refund of provisional capital not placed in-service. After the determination of any refund under the capital review process, PacifiCorp's restated actual rate of return will be compared against the authorized rate of return to determine if any deferral is necessary under Washington's multiyear rate plan legislation. In July 2024, PacifiCorp submitted a provisional capital report for calendar year 2023, which did not result in any refund, and is undergoing review by parties in February 2025.

In June 2023, PacifiCorp filed its PCAM to recover deferred net power costs from 2022. The filing requested recovery of over \$71 million, which PacifiCorp proposed to recover over a two-year period with interest, resulting in a rate increase of \$37 million, or 9.5%, to become effective January 1, 2024. In November 2023, the WUTC suspended PacifiCorp's PCAM filing in response to an intervening party's petition for adjudication request. PacifiCorp's hedging practices were evaluated in the adjudicative proceeding that was heard in June 2024. On October 30, 2024, the WUTC found that PacifiCorp's hedging practices were prudent for 2022 and approved recovery of \$70 million of net power costs over a two-year period effective November 7, 2024.

In June 2024, PacifiCorp filed its PCAM to recover deferred net power costs from 2023. The filing requested a rate increase of \$85 million, or 20.5%, effective October 1, 2024. In September 2024, the WUTC suspended PacifiCorp's 2023 PCAM filing in response to WUTC staff's submission for adjudication due to the pending nature of the 2022 PCAM. In December 2024, a multi-party stipulation was filed that the WUTC approved in January 2025. A rate increase of \$85 million, or 20.6% over a one-year period, went into effect on February 1, 2025.

Idaho

In April 2024, PacifiCorp filed its ECAM to recover deferred net power costs from 2023. The filing requested a rate increase of \$33 million, or 10.5%, effective June 1, 2024. In May 2024, the IPUC approved a rate increase of \$30 million, or 9.7%, effective June 1, 2024, that excluded costs associated with the Washington Cap and Invest program. In June 2024, PacifiCorp filed a petition for reconsideration of the disallowed costs, and in July 2024, the IPUC granted the request for reconsideration. PacifiCorp filed comments in September 2024, and in October 2024, the IPUC issued a decision denying reconsideration of its May order. Subsequently, in November 2024, PacifiCorp filed an appeal with the Idaho Supreme Court regarding the IPUC's order, and a schedule for that case is currently pending. Per the 2024 Idaho general rate case settlement discussed below, the rate increase approved for the ECAM will be spread over a two-year period.

In May 2024, PacifiCorp filed a general rate case requesting a rate increase of \$92 million over two years. The request sought an increase of \$66 million, or 19.4%, effective January 1, 2025, and a second increase of \$26 million, or 7.4%, effective January 1, 2026. The request included increased net power costs, capital investments in transmission and wind-powered generating facilities, higher insurance premiums for third-party liability coverage and proposed funding for a catastrophic fire fund. In October 2024, the IPUC issued a notice of suspension regarding PacifiCorp's general rate case application, suspending the rate effective date for 60 days, from January 1, 2025, to March 2, 2025. The notice also authorized PacifiCorp to track for future recovery the revenue requirement increase ultimately granted by the IPUC from January 1, 2025, until the new rates become effective. In November 2024, PacifiCorp reached a settlement with parties in its Idaho general rate case. The settlement includes a \$58 million base rate increase, or 16.8%, effective January 1, 2025. With the implementation of a rate mitigation measure, which reduces the current ECAM recovery by 50% and recovers the remaining balance over two years, the net rate increase is \$25 million, or 7.4%. The agreement includes recovery of all capital investments, and the parties agreed to a full recovery of the current insurance premiums and the deferred insurance premiums dating back to August 2023. The agreement also allows PacifiCorp to defer differences in actual insurance premiums until the next general rate case. PacifiCorp agreed to withdraw its proposal for a catastrophic fire fund and not to file another general rate case with new rates effective before January 1, 2027. In January 2025, the IPUC approved the settlement as filed, but adjusted the effective date to February 1, 2025.

California

In May 2022, PacifiCorp filed a general rate case requesting an overall rate change of \$28 million, or 25.7%, to become effective January 1, 2023. In November 2022, the CPUC granted the requested rate effective date and directed PacifiCorp to establish a memorandum account to track the change in rates beginning January 1, 2023 until the new rates become effective, upon the issuance of a decision in late 2023. PacifiCorp filed rebuttal testimony in February 2023 with a slight adjustment of an overall rate increase of \$27 million, or 25.0%. Also in February 2023, the CPUC issued a ruling requesting additional information on PacifiCorp's wildfire and risk analyses and requested additional information regarding wildfire memorandum accounts. In March 2023, the CPUC split the general rate case into two tracks. The first track addresses the general rate case and the second track addresses the wildfire memorandum accounts. In October 2023, PacifiCorp filed updated testimony in the first track that removed the costs considered in the second track, as directed by the CPUC. The updated testimony clarified that the rate increase for the first track is \$22 million, or 20.1%. In December 2023, the CPUC issued an order for the first track approving a rate increase of \$19 million, or 17.5%, effective January 12, 2024. Additionally, the CPUC approved recovery of \$19 million associated with the aforementioned memorandum account over three years. In the second track of the general rate case, PacifiCorp filed the independent audit of the wildfire memorandum accounts in January 2024, indicating no findings. In January 2025, the CPUC issued a proposed decision authorizing PacifiCorp to recover \$36 million related to historic wildfire mitigation costs. A final decision authorizing PacifiCorp to recover these costs over six years is anticipated by early March 2025.

In September 2023, PacifiCorp filed its 2024 combined ECAC and GHG related costs application requesting an overall rate increase of \$30 million, or 25.0%, effective March 1, 2024. Approximately \$36 million of the increase is attributed to the ECAC rate, which is offset by a \$6 million decrease to the GHG rate. In January 2024, PacifiCorp filed a joint motion for approval of the GHG portion of the filing. In March 2024, the CPUC approved the joint motion and the GHG related changes went into effect March 12, 2024 and April 1, 2024. In June 2024, PacifiCorp filed a joint motion for approval to settle the ECAC portion of the filing. The joint motion would result in an overall rate increase of \$23 million, or 19.3%. The ECAC settlement adjusted the ECAC balancing rate to be amortized over 21 months and maintained a one-year amortization for the ECAC offset rate. In November 2024, the CPUC issued a final order approving the settlement, with a rate effective date of November 22, 2024.

In September 2024, PacifiCorp filed to recover costs recorded in the catastrophic events memorandum account requesting a rate increase of \$15 million, or 10.2%, over approximately two years, effective March 1, 2025. PacifiCorp anticipates rates to be effective by the fourth quarter of 2025.

Deferral Accounting Treatment for Increased Costs Associated with Wildfires

In June 2023, PacifiCorp filed deferral applications with the UPSC, the OPUC, the WPSC, the WUTC and the IPUC to track the costs associated with third-party liability from litigation due to the 2020 Wildfires. The deferred accounting applications preserve PacifiCorp's ability to seek recovery in the future in the event the outcome could potentially impact its financial stability. PacifiCorp does not expect to determine if it will seek recovery until the appeals process associated with the 2020 Wildfires litigation has concluded. Subsequent to filing the applications in 2023, PacifiCorp filed motions to withdraw without prejudice with the UPSC and the IPUC that were accepted by both commissions. These filings preserve PacifiCorp's ability to file for deferred accounting treatment when the actual liability costs are more certain. In September 2024, PacifiCorp filed a motion to withdraw without prejudice with the WPSC that was approved in October 2024.

In June 2023, PacifiCorp filed an application with the CPUC for authority to establish a Wildfire Expense Memorandum Account to track the costs associated with third-party liability from litigation due to the 2020 Wildfires, increased insurance premium costs associated with third-party liability coverage and costs associated with potential liability for future catastrophic wildfires. The CPUC issued a proposed decision in February 2024. However, in March 2024, PacifiCorp filed a motion to stay the proceeding in order to re-evaluate the allocation of wildfire liability costs to California customers, and in April 2024, the CPUC granted the stay until December 2024. In December 2024, the CPUC determined that an extension of the stay was necessary and extended it to September 2025.

In August 2023, PacifiCorp filed deferral applications with the UPSC, the OPUC, the WUTC and the IPUC for costs associated with increased insurance premium costs associated with third-party liability coverage. In December 2023, PacifiCorp filed a deferral application with the WPSC for the increased insurance premium costs. The IPUC and the OPUC approved the request for authorization to defer the increased insurance premium costs in December 2023 and January 2024, respectively. Recovery of deferred amounts was addressed in the Idaho general rate case settlement and the Oregon general rate case order as described above. In March 2024, the UPSC denied the application for deferral accounting. In April 2024, PacifiCorp filed a request for review and reconsideration of the legal conclusions in the UPSC order. In May 2024, the UPSC granted PacifiCorp's application for rehearing, and as described above, this application is expected to be resolved through the Utah general rate case. In October 2024, the WPSC approved an August 2024 all-party stipulation allowing for deferred accounting for the increased insurance premium costs and recovery of the deferred amounts is being addressed in the pending general rate case described above.

MidAmerican Energy

2025 Solar Reliability Project

In February 2025, MidAmerican Energy filed an application with the IUC for advance ratemaking principles for MidAmerican Energy's 2025 Solar Reliability Project. The application asks the IUC to approve installation of up to 800 MWs of new solar generation in Iowa to meet capacity needs driven by load growth and regional capacity requirements. MidAmerican Energy asked the IUC to issue a final decision by August 2025. If approved, MidAmerican Energy expects to begin construction in 2026 and place the project's facilities in-service through 2027 and 2028.

Iowa Transmission Legislation

In June 2020, Iowa enacted legislation that grants incumbent electric transmission owners the right to construct, own and maintain electric transmission lines that have been approved for construction in a federally registered planning authority's transmission plan and that connect to the incumbent electric transmission owner's facility. This Right of First Refusal ("ROFR") law gave MidAmerican Energy, as an incumbent electric transmission owner, the legal right to construct, own and maintain transmission lines in MidAmerican Energy's service territory that have been approved by the MISO (or another federally registered planning authority) and are eligible to receive regional cost allocation. In October 2020, national transmission interests filed a lawsuit that challenged the law on state constitutional grounds. After an appeal in which the Iowa Supreme Court held the national transmission interests had standing to challenge the law and remanded the case to the Iowa district court for a decision on the merits, the district court, in December 2023, found the legislature impermissibly "log-rolled" the ROFR law into a state appropriations bill in violation of the title and single-subject provisions of the Iowa Constitution and held that the law was unconstitutional and unenforceable. The district court issued an injunction that enjoins MidAmerican Energy and ITC Midwest from further developing the Long Range Transmission Projects ("LRTP") Tranche 1 projects to the extent authority to construct was claimed pursuant to, under, or in reliance on the invalid ROFR law, but allows either company to proceed with projects assigned in a manner not relying on the claimed existence of the law.

In April 2024, MidAmerican Energy and ITC Midwest filed an appeal to the Iowa Supreme Court that challenges the application of the injunction to the LRTP Tranche 1 projects; MISO filed an amicus brief that supports the positions taken by MidAmerican Energy and ITC Midwest. The appeal remains pending before the Iowa Supreme Court, and MidAmerican Energy expects a ruling on the appeal by mid-2025. The district court injunction remains in effect while the appeal is pending.

In May 2024, MISO issued a public notice that advised it was proceeding with a variance analysis under its tariff to assess actions that could be taken to mitigate the obstacle to construct posed by the district court injunction. The notice confirmed the injunction did not change ownership of the projects or cause any project facility classification to be modified to a competitive transmission facility under MISO's tariff. It also confirmed the injunction did not suspend either company's obligation to construct the projects under MISO's tariff. In August 2024, MISO issued notice of the outcome of its variance analysis, determining that a mitigation plan was the appropriate outcome under the MISO tariff. As part of the mitigation plan, MISO's Competitive Transmission Executive Committee determined the projects should be assigned to the incumbent transmission owners under the transmission owners agreement, which results in no change to the project assignments. MISO's notice reaffirmed that MidAmerican Energy and ITC Midwest remain obligated to construct the projects under MISO's tariff. In October 2024, the national transmission interests filed a motion with the district court that asks the court to enforce the injunction and enjoin MidAmerican Energy and ITC Midwest from proceeding with the projects under MISO's mitigation plan, arguing the injunction remains applicable because the mitigation plan relies on the continued existence of the ROFR law. MidAmerican Energy and ITC Midwest resisted, arguing that the motion is legally and factually erroneous and that the injunction would improperly interfere with MISO's exclusive authority under federally authorized tariffs. A hearing on the motion was held on February 20, 2025; a decision from the court is pending.

The litigation regarding the ROFR law would only affect the manner in which MidAmerican Energy would secure the right to construct transmission lines that are eligible for regional cost allocation and are otherwise subject to competitive bidding under the MISO tariff; it does not negatively affect or implicate MidAmerican Energy's ongoing rights to construct any other transmission lines, including lines required to serve new or expanded retail load, connect new generators or meet reliability criteria.

NV Energy (Nevada Power and Sierra Pacific)

Regulatory Rate Review

In February 2024, Sierra Pacific filed electric and gas regulatory rate reviews with the PUCN that requested annual revenue increases of \$95 million, or 8.8% and \$11 million, or 4.9%, respectively. Sierra Pacific filed the certification filing that updated the electric and gas filings to requested annual revenue increases of \$96 million, or 9.5% and \$12 million, or 6.4%, respectively. Hearings in the cost of capital phase were held in June 2024 and the hearings for the revenue requirement phase were held in July 2024. The hearings in the rate design phase were held in August 2024. In September 2024, the PUCN issued an order approving an increase in base rates for electric of \$40 million and for gas of \$8 million. In October 2024, Sierra Pacific filed a petition for reconsideration and clarification of the order. In November 2024, the PUCN issued a final order approving in part and denying in part the petition for reconsideration.

In February 2025, Nevada Power filed an electric regulatory rate review with the PUCN that requested an annual revenue increase of \$215 million, or 9.0%. An order is expected by the third quarter of 2025 and, if approved, rates are proposed to be effective October 1, 2025.

Wildfire Self-Insurance Policy Filing

In January 2025, the Nevada Utilities filed applications for approval of the establishment and associated cost recovery of a Wildfire Self-Insurance Policy. In their applications, the Nevada Utilities request first, that the PUCN issue an order determining that it is reasonable and prudent for the Nevada Utilities to establish a \$500 million wildfire self-insurance policy (the "Policy") in order to have additional wildfire liability insurance in place in the event that a catastrophic wildfire in Nevada is alleged to be caused or exacerbated by utility equipment. The Policy would provide \$500 million in additional coverage for the Nevada Utilities for third-party claims, and it would be in excess to the commercial wildfire liability insurance the Nevada Utilities currently possess. Second, the applications request approval to collect the costs for the Policy in rates over a ten-year period. An order is expected in 2025.

BHE Pipeline Group

BHE GT&S

In November 2023, CGT filed a general rate case for its FERC-jurisdictional services, with proposed rates to be effective January 1, 2024. CGT's current rates were established by a 2011 settlement. CGT proposed an annual cost-of-service of \$167 million, and requested increases in various rates, including Zone 1 general system transmission rates by 84% and Zone 2 general system transmission rates by 23%. In December 2023, the FERC suspended the rate changes for five months following the proposed effective date, until June 1, 2024, subject to refund. In August 2024, a settlement agreement was filed with the FERC, resolving CGT's general rate case for its FERC-jurisdictional services and providing for increased service rates and depreciation rates. Under the terms of the settlement agreement, CGT's rates result in an average annual increase to firm transmission revenues of \$25 million over the settlement period and an increase in annual depreciation expense of \$8 million, compared to the rates in effect prior to June 1, 2024. In November 2024, the FERC approved the settlement agreement.

BHE Transmission

AltaLink

2024-2025 General Tariff Application

In April 2023, AltaLink filed its 2024-2025 GTA with the AUC. In August 2023, AltaLink refiled its 2024-2025 GTA, which included amendments to its planned Wildfire Mitigation Plan ("WMP") expenditures and a new request for a wildfire damages deferral account in response to unprecedented wildfire events in its service area. The amendment sought approval for increased WMP capital expenditures from C\$16 million to C\$39 million in 2024 and from C\$15 million to C\$38 million for 2025. In December 2023, the AUC approved 2024 interim transmission tariffs for AltaLink of C\$74 million per month effective January 1, 2024. Subsequently, AltaLink informed the AUC that it reached a partial negotiated settlement with customer groups on the majority of its 2024-2025 GTA and filed the agreement with the AUC for approval in December 2023. In February 2024, the AUC approved the negotiated settlement agreement as filed. The agreement did not include AltaLink's proposed wildfire deferral account, certain components of the WMP, actual salvage expenditures from 2019-2023 and forecast salvage expenditures for 2024-2025.

In June 2024, the AUC issued its decision with respect to AltaLink's 2024-2025 GTA and matters excluded from the negotiated settlement (the "GTA Decision"). The AUC approved the previously denied C\$99 million of actual salvage costs incurred from 2019-2021 and the 2022-2025 salvage expenditures of C\$124 million, subject to changes arising from revised WMP capital expenditures. The AUC also approved AltaLink's transition to the capitalization of site preparation or salvage costs for capital replacement projects starting in 2024. However, the AUC did not approve the recovery of C\$11 million of debt and equity returns for 2022-2023 related to the previously denied C\$99 million salvage costs. The AUC also approved C\$29 million of forecast capital expenditures, including capitalized salvage, related to AltaLink's 2024-2025 WMP, which is generally consistent with the approved wildfire capital expenditures in AltaLink's 2022-2023 WMP. The AUC did not approve AltaLink's August 2023 request for an incremental C\$46 million in forecast wildfire mitigation capital expenditures. The AUC denied AltaLink's proposed wildfire damages deferral account stating that AltaLink currently has multiple layers of protection to address the risk of liability for wildfire-related third-party damages.

In August 2024, AltaLink filed its 2024-2025 GTA compliance filing ("GTA Compliance Filing"), which reflected the 9.28% return on equity for 2024 that was approved in the Generic Cost of Capital proceeding and the capitalization of site preparation costs as approved by the AUC. In November 2024, the AUC issued a decision in the GTA Compliance Filing approving AltaLink's revenue requirements of C\$900 million for 2024 and C\$906 million for 2025. The AUC directed AltaLink to submit a post-disposition filing updating the 2025 revenue requirement to reflect a return on equity of 8.97%, as determined in the separate Generic Cost of Capital proceeding, and to provide the associated monthly transmission tariffs for 2024 and 2025 with an effective date of December 1, 2024. The AUC approved the revised requirements, subject to the updates to return on equity to be provided in the post-disposition filing. In December 2024, the AUC issued a decision confirming that the 2025 revenue requirements and 2024 and 2025 transmission tariffs filed as post-disposition documents by AltaLink reflect the AUC's approvals and directions, and approved them as final. The AUC approved final transmission tariffs for AltaLink of C\$98 million for December 2024 and C\$75 million per month for 2025. The AUC also approved AltaLink's 2025 revenue requirements at C\$889 million.

BHE U.S. Transmission

In January 2025, ETT filed a request with the Public Utilities Commission of Texas ("PUCT") for a \$57 million annual base rate increase over its adjusted test year revenues which includes interim transmission rate updates. The rate case seeks a prudence review determination on cumulative capital additions included in interim rates since the initial base regulatory review in 2007. A procedural schedule for the case is pending.

ENVIRONMENTAL LAWS AND REGULATIONS

Each Registrant is subject to federal, state, local and foreign laws and regulations regarding air quality, climate change, emissions performance standards, water quality, coal ash disposal and other environmental matters that have the potential to impact each Registrant's current and future operations. In addition to imposing continuing compliance obligations, these laws and regulations provide regulators with the authority to levy substantial penalties for noncompliance, including fines, injunctive relief and other sanctions. These laws and regulations are administered by various federal, state, local and international agencies. Each Registrant believes it is in material compliance with all applicable laws and regulations, although many laws and regulations are subject to interpretation that may ultimately be resolved by the courts.

The Company has cumulative investments in (i) owned wind, solar and geothermal generating facilities of \$35.4 billion and (ii) wind tax equity investments of \$7.3 billion and has ceased coal operations at 18 coal-fueled generation facilities. As a result, as of December 31, 2024, the Company reduced its annual GHG emissions by more than 38% as compared to 2005 levels. To the extent it is beneficial for customers and consistent with regulatory provisions, the Company plans to continue investing in wind, solar and other low-carbon generation and storage in the future, including (i) \$5.1 billion on the construction of renewable generating facilities and repowering certain existing wind-powered generating facilities through 2027 and (ii) \$0.6 billion on the construction of electric battery storage facilities through 2027, and to cease coal operations at additional coal-fueled generation facilities in a reliable and cost-effective manner, thereby achieving a 50% reduction in GHG emissions from 2005 levels in 2030. Refer to "Liquidity and Capital Resources" of each respective Registrant in Item 7 of this Form 10-K for discussion of each Registrant's renewable generation-related capital expenditures.

On August 16, 2022, the Inflation Reduction Act of 2022 (the "2022 Act") was signed into law. The 2022 Act contains numerous provisions, including expanded tax credits for clean energy incentives and a 15% corporate alternative minimum income tax on "adjusted financial statement income". The provisions of the 2022 Act become effective for tax years beginning after December 31, 2022. The Company currently does not expect a material impact on its consolidated financial statements. However, the Company expects future guidance from the Treasury Department and will continue to evaluate the impact of the 2022 Act as more guidance becomes available.

On January 20, 2025, President Trump issued a series of U.S. federal executive orders, including a memorandum establishing a regulatory freeze pending review. The memo prohibits submission of rules and guidance documents to the Federal Register without direct review, requires immediate withdrawal of rules and guidance documents submitted to the Federal Register but not yet published, and, for rules and guidance documents published but not yet having taken effect, consideration of a 60-day delay and possible additional comment period. Additional executive orders direct the heads of all administrative agencies to review all existing regulations, orders, guidance documents, policies, settlements, consent orders and any other agency actions and develop action plans to suspend, revise or rescind all agency actions identified as unduly burdensome. Until the agencies complete reviews and take final action consistent with these directives, the relevant Registrant cannot determine the impact and whether additional action will be necessary.

Air Quality Regulations

The Clean Air Act, as well as state laws and regulations impacting air emissions, provides a framework for protecting and improving the nation's air quality and controlling sources of air emissions. These laws and regulations continue to be promulgated and implemented and will impact the operation of BHE's generating facilities and require them to reduce emissions at those facilities to comply with the requirements. In addition, the potential adoption of state or federal clean energy standards, which include low-carbon, non-carbon and renewable electricity generating resources, may also impact electricity generators and natural gas providers.

National Ambient Air Quality Standards

Under the authority of the Clean Air Act, the EPA sets minimum NAAQS for six principal pollutants, consisting of carbon monoxide, lead, NO_x, particulate matter, ozone and SO₂, considered harmful to public health and the environment. Areas that achieve the standards, as determined by ambient air quality monitoring, are characterized as being in attainment, while those that fail to meet the standards are designated as being nonattainment areas. Generally, sources of emissions in a nonattainment area that are determined to contribute to the nonattainment are required to reduce emissions. Currently, with the exceptions described in the following paragraphs, air quality monitoring data indicates that all counties where the relevant Registrant's major emission sources are located are in attainment of the current NAAQS.

On June 4, 2018, the EPA published final ozone designations for much of the U.S. Relevant to the Registrants, these designations include classifying Yuma County, Arizona; Clark County, Nevada; and the Northern Wasatch Front, Southern Wasatch Front and Duchesne and Uintah counties in Utah as nonattainment-marginal with the 2015 ozone standard. These areas were required to meet the 2015 standard three years from the August 3, 2018, effective date. All other areas relevant to the Registrants were designated attainment/unclassifiable with this same action. However, on January 29, 2021, the D.C. Circuit vacated several provisions of the 2018 implementing rules for the 2015 ozone standards for contravening the Clean Air Act. The EPA and environmental groups finalized a consent decree in January 2022 that sets deadlines for the agency to approve or disapprove the "good neighbor" provisions of interstate ozone plans of dozens of states. Relevant to the Registrants, the EPA must, by April 30, 2022, propose to approve or disapprove the interstate ozone SIPs of Alabama, Iowa, Maryland, Michigan, Minnesota, New York, Ohio, Pennsylvania, Texas, West Virginia and Wisconsin. On February 22, 2022, the EPA published a series of proposed decisions to disapprove the SIPs for interstate ozone transport of 19 states. Relevant to the Registrants, these states include Alabama, Maryland, Michigan, Minnesota, New York, Ohio, West Virginia and Wisconsin. The EPA also proposed to approve Iowa's SIP after re-analyzing the state's data. In addition, the EPA must approve or disapprove the interstate plans of Arizona, California, Nevada and Wyoming. On April 15, 2022, the EPA issued its final rule approving Iowa's SIP as meeting the good neighbor provisions for the 2015 ozone standard. On May 24, 2022, the EPA disapproved the Utah and Wyoming interstate ozone SIPs. On January 30, 2023, the EPA entered into a stipulated extension to the deadline for action on the Wyoming SIP, setting a new deadline of December 15, 2023. The EPA explained that the extra time is needed to fully consider updated air quality information and public comments. The EPA published its proposed approval of Wyoming's SIP on August 14, 2023 and finalized the approval December 19, 2023. As a result, Wyoming is not subject to the Good Neighbor Rule, discussed below, and litigation over Wyoming's SIP was terminated after the effective date of the rule on January 18, 2024. The EPA also reevaluated SIPs for Tennessee and Arizona. On January 31, 2023, the EPA issued final disapproval of the 19 SIPs proposed in April 2022, setting the stage to include those states in the federal implementation plan described under the Cross-State Air Pollution Rule. Separately, on March 28, 2022, the EPA proposed determinations as to whether certain areas have achieved levels of ground-level ozone pollution that meet the 2008 and 2015 ozone NAAQS. Relevant to Registrants, the Southern Wasatch Front in Utah and Yuma, Arizona are proposed to have met the 2015 ozone standard; and the Cincinnati area of Ohio and Kentucky and the Northern Wasatch Front in Utah are proposed to have not met the 2015 ozone standard and to be reclassified as Moderate Non-Attainment, and have until August 3, 2024, to meet the standard. In June 2022, the EPA took final action to redesignate the Ohio portion of the Cincinnati area to attainment status and no further action is required. In November 2022, the EPA finalized the redesignations of the Southern Wasatch Front area in Utah and Yuma, Arizona to attainment, and also finalized a finding of failure to attain and redesignation to marginal nonattainment for the Kentucky portion of the Cincinnati area. In September 2022, after achieving acceptable levels of the ozone NAAQS, the Commonwealth of Kentucky requested that the EPA redesignate the Kentucky portion of the Cincinnati area to attainment for the 2015 ozone standard. The EPA took final action in September 2023 to approve Kentucky's plan and to redesignate the Kentucky portion of the Cincinnati area to attainment for the 2015 ozone standard. In December 2024, the EPA finalized findings of failure to attain and reclassification of the Northern Wasatch Front area in Utah and the Las Vegas Valley area of Clark County, Nevada, as "serious" for the 2015 ozone standard. As a result, Utah and Nevada must submit to the EPA certain SIP revisions and may require permitting changes for the relevant Registrants' facilities. In October 2024, the EPA proposed to set a deadline of 18 months from the effective date of the reclassification, or no later than January 1, 2026. Also in October 2024, the EPA entered into a settlement agreement with environmental groups concerning the agency's delay in reviewing and revising, if necessary, the primary health-based NAAQS for NO_x. Under the agreement, the EPA must sign a proposed NO_x NAAQS update by January 17, 2028, and finalize it by November 10, 2028. On December 27, 2024, consistent with the terms of a separate settlement agreement, the EPA finalized action to revise the secondary NAAQS for SO₂ and to retain the existing secondary standards for NO_x and PM. Any action may be subject to further review by the new administration. Until the EPA takes final action to address implementation deadlines for newly reclassified areas and the affected states submit any required SIPs, the relevant Registrants cannot determine the impacts of these actions.

On February 7, 2024, the EPA released final standards for fine particulate matter, PM_{2.5}. The EPA strengthened the primary, health-based annual PM_{2.5} standard from 12 micrograms per cubic meter to 9 micrograms per cubic meter. The standards were last updated in 2012. Most PM_{2.5} particles form in the atmosphere as a result of chemical reactions of substances, such as sulfur dioxide and nitrogen oxides, that are emitted from power plants, industrial sources and automobiles. National ambient air quality standards are implemented through compliance plans submitted by states and tribes that are then approved by the EPA. The EPA stated that 119 counties in the 48 contiguous states do not meet the revised standard but predicted that that number would be reduced to 52 counties by 2032, the earliest year by which a compliance requirement is anticipated. 23 of these 52 counties are located in California. There are no immediate impacts on the relevant Registrants. Until additional rulemaking and litigation is exhausted, the relevant Registrants cannot determine the full impacts of the revised standard.

New Source Performance Standards for Nitrogen Oxides

On December 13, 2024, the EPA published a proposed rule to strengthen limits on emissions of NO_x from new gas-fueled combustion turbines. The agency last updated nitrogen oxides emissions limits on new, modified and reconstructed fossil-fueled stationary combustion turbines in 2006. The proposed rule wraps up a settlement the agency reached with environmental groups in 2023. The proposed rule covers stationary combustion turbines that are located at power plants and industrial sources like pipeline compressor stations; chemical and manufacturing plants; oil fields; landfills; and institutional facilities, among others. The EPA proposes to require the addition of post-combustion SCR as the best system of emissions reduction for most combustion turbines. As part of the same proposed rule, the EPA also said it will maintain the current standards for SO₂ emissions because the use of low-sulfur fuels remains the best system of emissions reduction for that pollutant. The EPA will accept comments through March 13, 2025. Until rulemaking is concluded and potential litigation is exhausted, the relevant Registrants cannot determine the full impacts of the rule.

Mercury and Air Toxics Standards

In March 2011, the EPA proposed a rule that requires coal-fueled generating facilities to reduce mercury emissions and other hazardous air pollutants through the establishment of "Maximum Achievable Control Technology" standards. The final MATS became effective on April 16, 2012, and required that new and existing coal-fueled generating facilities achieve emission standards for mercury, acid gases and other non-mercury hazardous air pollutants. Existing sources were required to comply with the new standards by April 16, 2015, with the potential for individual sources to obtain an extension of up to one additional year, at the discretion of the Title V permitting authority, to complete installation of controls or for transmission system reliability reasons. The relevant Registrants have completed emission reduction projects and unit retirements to comply with the final rule's standards for acid gases and non-mercury metallic hazardous air pollutants.

On April 25, 2024, the EPA finalized revisions to several aspects of the MATS rule following the agency's review of the 2020 Residual Risk and Technology Review. The EPA made two specific standard changes; one applicable to all covered units and one specific to the existing lignite subcategory. The relevant Registrants are not affected by the changes to the lignite subcategory. The EPA set a more stringent standard for emissions of filterable particulate matter, the surrogate standard for non-mercury metals for coal-fueled electric generating units, and required continuous emissions monitoring for filterable particulate matter to demonstrate compliance with the revised standard. Compliance is due no later than three years after the effective date of the final rule, with limited opportunities for a one-year extension. The relevant Registrants have determined that compliance can be achieved with existing controls, except for PacifiCorp's 10% stake in two units at the Colstrip generating facility, which will require either expensive equipment upgrades or retirement by July 2027. Several states and industry groups have challenged the MATS rule; motions to stay were denied by the D.C. Circuit and the U.S. Supreme Court. The D.C. Circuit will hear oral arguments in the case on March 27, 2025. Until litigation is exhausted, PacifiCorp cannot determine the full impacts of the final rule for the Colstrip units.

Cross-State Air Pollution Rule

The EPA promulgated an initial rule in March 2005 to reduce emissions of NO_x and SO₂, precursors of ozone and particulate matter, from down-wind sources in the eastern U.S. to reduce emissions by implementing a plan based on a market-based cap-and-trade system, emissions reductions, or both. After numerous appeals, the CSAPR was promulgated to address interstate transport of SO₂ and NO_x emissions in 27 Eastern and Midwestern states. In March 2022, the EPA released its Good Neighbor Rule, which contains proposed revisions to the CSAPR framework and is intended to address ozone transport for the 2015 ozone NAAQS. In March 2023, the EPA released the final Good Neighbor Rule. For the first time, the EPA included additional sectors beyond the electric generation sector in the 2023 expanded CSAPR program. Relevant to the Registrants, this includes the pipeline transportation of natural gas. Requirements for that sector focus on emissions reductions from reciprocating internal combustion engines involved in the transport of natural gas and take effect in 2026. There is no access to allowance trading for the non-electric generation sectors. The EPA excluded emergency engines and engines that do not operate during the ozone season, included a facility-wide averaging plan and eased requirements for monitoring in the final rule. BHE GT&S operates 157 affected units; Northern Natural Gas operates 18 affected units; and Kern River is not affected by the final rule. The electric generation sector remains the key industry regulated by the rule and will be subject to emissions allowance trading, which was slated to begin in summer 2023, but is on hold during the pendency of litigation. The final rule shifted the maximum daily backstop rate for coal-fueled generating units, which drives the installation of new controls or curtailment, to take effect in 2030 instead of 2027. PacifiCorp's Hunter Units 1-3 and Huntington Units 1-2, which do not have SCR controls, are impacted by the rule. PacifiCorp's 2023 IRP selected the installation of SNCR on the Hunter and Huntington Units by 2026 as part of the preferred portfolio. The level of NO_x allowances for the Utah units remains similar to 2021 levels, with significant reductions for the coal units beginning in 2026. The daily limit, which takes effect in 2030, will further restrict operation of coal-fueled units without SCR. NV Energy's fossil-fueled units are also covered by the final rule. North Valmy Units 1 and 2, which do not have SCR, will require additional controls or reduced operations during the ozone season if operated beyond 2025. In March 2024, the PUCN approved NV Energy's request to convert the existing coal-fueled generating facility at the North Valmy Generating Station to natural gas and to continue operation of Tracy Units 4 and 5 to 2049 with appropriate NO_x emissions controls. NV Energy anticipates the need to install additional controls to comply with Nevada's regional haze SIP, which will be re-submitted in 2025. The final controls will contemplate the potential need to meet the Good Neighbor Rule requirements pending outcomes of litigation. The EPA also deferred final action for Wyoming, pending further review of updated air quality and contribution modeling and analysis. The EPA ultimately approved Wyoming's SIP in December 2023. Additional notice and comment rulemaking, such as a supplemental rule, would be required to rescind Iowa's approved SIP and incorporate additional states into the program. The states of Nevada, Utah and Wyoming challenged the EPA's denials and deferral, respectively, of their interstate ozone transport SIPs in the Ninth, Tenth and D.C. Circuits. PacifiCorp also filed petitions with the court opposing the EPA's action in Utah and Wyoming. At the time of filing, at least 11 other states have challenged the EPA's action to disapprove SIPs in seven different federal courts of appeal. Stays have been granted by six circuit courts for SIP disapprovals in 12 states. Relevant to Registrants, the states of Nevada, Texas and Utah were granted stays. The final Good Neighbor Rule was published June 5, 2023 and took effect August 4, 2023. The EPA issued several interim final rules stating that the federal rule will not take effect in states in which the SIP disapprovals have been deferred or stayed. In addition to litigation over SIP disapprovals, there are numerous appeals of the final Good Neighbor Rule pending in four different circuit courts, and at least four motions to stay the final rule have been filed in four different circuit courts. On September 25, 2023, the D.C. Circuit denied the motion to stay the Good Neighbor Rule filed by several state and industry parties. The denial means that states that do not have stays on their SIP disapprovals are subject to the Good Neighbor Rule. However, the states of Ohio, Indiana and West Virginia filed a request for stay of the Good Neighbor Rule with the U.S. Supreme Court on October 13, 2023. Several industry groups representing utilities as well as pipeline, paper, cement and other industries affected by the rule filed supportive requests for stay on the same day. The U.S. Supreme Court heard oral arguments on the emergency stay requests on February 21, 2024, and granted the stay requests on June 27, 2024. Consequently, enforcement of the federal ozone transport rule is halted while litigation over the rule continues in the D.C. Circuit. On October 10, 2024, the EPA sent for White House Office of Management and Budget pre-publication review an action further explaining how the Good Neighbor Rule can function with fewer states than the 23 originally intended, after the U.S. Supreme Court stayed its implementation over doubts about the program's viability and fairness. The rule addresses the D.C. Circuit's September 2024 partial remand of the rule's record. On February 6, 2025, the EPA filed a motion requesting abeyance of litigation for 60 days to allow a transition to the new administration. On February 21, 2025, the D.C. Circuit denied the EPA's request to hold the litigation in abeyance and extending the briefing schedule through March 27, 2025.

On a parallel track, the Tenth Circuit Court of Appeals granted a motion filed by the EPA on February 27, 2024, transferring the Utah and Oklahoma SIP disapproval litigation to the D.C. Circuit. The D.C. Circuit granted a request to abate the litigation while PacifiCorp, Utah and other petitioners sought a review of the transfer order before the U.S. Supreme Court. The U.S. Supreme Court announced on October 21, 2024, that it would hear this and a related case concerning proper venue under the Clean Air Act. Arguments are anticipated to take place in spring 2025, with a decision by June 2025. In a July 5, 2024, motion filed with the D.C. Circuit, the EPA asked the court to consolidate and expedite all the remaining cases on the Ozone Transport Rule. The agency proposed a briefing schedule that would have opening briefs filed August 20, 2024, and final briefs filed November 12, 2024, with oral argument set before the end of 2024. On July 26, 2024, the D.C. Circuit continued abatement of the case until the U.S. Supreme Court acts on the petitions.

On January 24, 2024, the EPA released a supplemental proposal to expand the Good Neighbor Plan to an additional five states - Arizona, Iowa, Kansas, New Mexico and Tennessee. The EPA cites new modeling showing the states' significant contribution to ozone problems in downwind states. Under the proposal, fossil-fueled generating facilities in these five states would be required to participate in the allowance-based ozone season nitrogen oxides emissions trading program beginning in 2025. The EPA accepted comments on the supplemental proposal through May 16, 2024. The EPA submitted the final supplemental rule for interagency review in September 2024. In December 2024, the EPA withdrew the supplemental rule following a nationwide stay of the Good Neighbor Plan.

Until litigation is exhausted, the potential impacts to the relevant Registrants cannot be determined.

Regional Haze

First Planning Period

The EPA's Regional Haze Rule, finalized in 1999, requires states to develop and implement plans to improve visibility in designated federally protected areas ("Class I areas"). In accordance with the federal requirements, states are required to submit SIPs that address emissions from sources subject to visibility requirements and demonstrate progress towards achieving natural visibility requirements in Class I areas by 2064.

In June 2019, the state of Utah incorporated a BART alternative into its SIP for regional haze planning period one. The BART alternative makes the shutdown of PacifiCorp's Carbon generating facility enforceable under the SIP and removes the requirement to install SCR equipment on Hunter Units 1 and 2 and Huntington Units 1 and 2. The EPA approved the SIP revision with the BART alternative in October 2020. The EPA's actions also withdrew a prior FIP that required installation of SCR equipment on Hunter Units 1 and 2 and Huntington Units 1 and 2. Environmental groups challenged the Utah Regional Haze SIP Alternative in the Tenth Circuit Court of Appeals in January 2021. The Tenth Circuit denied the petition for review in August 2023. As a result, Utah has concluded its efforts for the regional haze first planning period.

The state of Wyoming issued two regional haze SIPs requiring the installation of SO₂, NO_x and particulate matter controls on certain PacifiCorp coal-fueled generating facilities in Wyoming. The EPA approved the SO₂ SIP in December 2012 and the EPA's approval was upheld on appeal by the Tenth Circuit in October 2014. The EPA's final action on the Wyoming SIP in 2014 approved the state's plan to have PacifiCorp install low-NO_x burners at Naughton Units 1 and 2, SCR controls at Naughton Unit 3 by December 2014, SCR controls at Jim Bridger Units 1 through 4 between 2015 and 2022, and low-NO_x burners at Dave Johnston Unit 4. The EPA disapproved a portion of the Wyoming SIP and issued a FIP for Dave Johnston Unit 3, where it required the installation of SCR controls by 2019 or, in lieu of installing SCR controls, a commitment to shut down Dave Johnston Unit 3 by 2027, its currently approved depreciable life. The EPA also disapproved a portion of the Wyoming SIP and issued a FIP for the Wyodak coal-fueled generating facility, requiring the installation of SCR controls by 2019. PacifiCorp filed an appeal of the EPA's final action on Wyodak in March 2014. The state of Wyoming and several environmental groups also filed an appeal of the EPA's final action. In September 2014, the Tenth Circuit issued a stay of the March 2019 compliance deadline for Wyodak, pending further action by the Tenth Circuit in the appeal. The parties worked to mediate claims under the Wyoming regional haze requirements until the abatement on litigation was lifted in September 2022. On August 15, 2023, the Tenth Circuit ruled in favor of Wyoming and remanded the Wyodak portion of Wyoming's state plan to the EPA for further review, with instructions to give appropriate deference to the state's determinations. For Naughton Units 1 and 2, the court determined the EPA properly approved Wyoming's Naughton determination and denied environmental groups' petition. Separately, on February 14, 2022, the First Judicial District Court for the State of Wyoming entered a consent decree reached between the state of Wyoming and PacifiCorp resolving claims of threatened violations of the Clean Air Act, the Wyoming Environmental Quality Act and the Wyoming Air Quality Standards and Regulations at the Jim Bridger facility. No penalties were imposed under the consent decree. Consistent with the terms and conditions of the consent decree, PacifiCorp converted Jim Bridger Units 1 and 2 to natural gas and met emissions limits consistent with that conversion by January 1, 2024. The EPA and PacifiCorp executed an administrative order on consent on June 9, 2022, covering compliance for Jim Bridger Units 1 and 2 under the regional haze rule. The federal order contains the same emission and operating limits as the Wyoming consent decree and adds federal approval of the compliance pathway outlined in the state consent decree, including revision of the SIP to include conversion of Jim Bridger Units 1 and 2 to natural gas. The order includes a one-year deadline to complete the SIP revision. On December 30, 2022, the Wyoming Air Quality Division submitted the state-approved revised regional haze SIP requiring natural gas conversion of Jim Bridger Units 1 and 2 to the EPA for approval. The Wyoming Air Quality Division also issued an air permit for the natural gas conversion of Jim Bridger Units 1 and 2 on December 28, 2022. PacifiCorp submitted a notice of compliance to the EPA on March 9, 2023, to certify completion of the Jim Bridger administrative compliance order requirements through compliance with the Wyoming consent decree and Wyoming's revised SIP submission. On April 10, 2024, the EPA proposed approval of Wyoming's regional haze SIP revision for the first planning period. The SIP includes enforceable emissions and heat input limits at Jim Bridger Units 1 and 2, consistent with the conversion of those units to natural gas. The EPA accepted comments on the proposed approval through May 10, 2024. As of the filing date, final action on the SIP has not occurred.

The state of Colorado first planning period regional haze SIP requires SCR equipment at Craig Unit 2 and Hayden Units 1 and 2, in which PacifiCorp has interests. Each of those regional haze compliance projects are in-service. In addition, in February 2015, the state of Colorado finalized an amendment to its regional haze SIP relating to Craig Unit 1, in which PacifiCorp has an interest, to require the installation of SCR controls by 2021. In September 2016, the owners of Craig Units 1 and 2 reached an agreement with state and federal agencies and certain environmental groups that were parties to the previous settlement requiring SCR to retire Unit 1 by December 31, 2025, in lieu of SCR installation, or alternatively to remove the unit from coal-fueled service by August 31, 2021 with an option to convert the unit to natural gas by August 31, 2023, in lieu of SCR installation. The terms of the agreement were approved by the Colorado Air Quality Board in December 2016, incorporated into an amended Colorado regional haze SIP in 2017 and approved by the EPA in August 2018. PacifiCorp retained a December 31, 2025, retirement date for Craig Unit 1 in its 2023 IRP, which will satisfy its regional haze obligations in the state of Colorado.

Second Planning Period

Nevada, Utah and Wyoming each submitted regional haze SIPs for the regional haze second planning period to the EPA and received completeness determinations in August 2022. The EPA was required to make final determinations on the SIPs by August 2023. The states of Utah and Wyoming filed deadline suits in the Utah and Wyoming federal district courts in October and November 2023, respectively, asking the court to require the EPA to perform its statutory duty to approve or disapprove the states' regional haze second planning period SIPs. PacifiCorp also filed a deadline suit in both courts. Three environmental groups filed similar deadline suits in the federal district court in Washington, D.C. for seven different states on June 15, 2023. The environmental groups amended their lawsuit on November 10, 2023, after Wyoming and PacifiCorp's suits were filed, to include Utah's and Wyoming's state plans. PacifiCorp intervened in the D.C. district court case and asked that court to stay the Utah and Wyoming cases in that court while they proceed in the relevant federal courts in Utah and Wyoming. The EPA published a proposed regional haze second planning period settlement agreement with environmental groups on March 29, 2024, that would require the agency to take final action approving or denying SIPs under a rolling series of deadlines through 2026. The proposed consent decree was subject to public comments through April 29, 2024, before being adopted by the court on July 12, 2024. The consent decree sets final deadlines for the EPA to approve or disapprove the haze plans of 32 states. Relevant to the Registrants, the EPA would be required to take final action on Utah's and Wyoming's plans by November 22, 2024; Texas' plan by May 30, 2025; and Nevada's plan by December 15, 2025. Utah, Wyoming and PacifiCorp withdrew the deadline suits in their respective state federal district courts. On August 1, 2024, the EPA proposed to partially approve and partially disapprove Wyoming's SIP for the second planning period and accepted comments on the proposal through September 3, 2024. On August 19, 2024, the EPA proposed to partially approve and partially disapprove Utah's SIP for the second planning period and accepted comments on the proposal through September 18, 2024. On December 2, 2024, the EPA finalized the partial approval and partial disapproval of Utah's and Wyoming's SIPs. As a result, the EPA is required to impose a federal implementation plan within two years unless Wyoming and Utah submit a new plan that the agency approves. On October 15, 2024, the EPA proposed to partially approve and partially disapprove Texas' SIP for the second planning period and will accept comments on the proposal through November 14, 2024. On January 31, 2025, the state of Wyoming, PacifiCorp and other parties filed petitions for review with the Tenth Circuit Court of Appeals. The petitions contest EPA's disapproval of Wyoming's regional haze SIP for the second planning period. On February 19, 2025, the Tenth Circuit issued a mediation notice to all parties in the Wyoming litigation, setting a mediation conference for February 26, 2025. Also on January 31, 2025, PacifiCorp and other parties filed a petition for review with the Tenth Circuit Court of Appeals, contesting EPA's disapproval of Utah's regional haze SIP for the second planning period. PacifiCorp is working with the EPA on potential mediation and abatement of the Utah litigation. Until litigation is exhausted and any additional rulemaking is completed by the EPA, any potential impacts to the relevant Registrants cannot be determined.

In August 2023, the Nevada Utilities filed a Joint Application for approval of the Fifth Amendment to the 2021 Joint Integrated Resource Plan. The Fifth Amendment seeks, in part, to convert the existing coal-fueled North Valmy Generating Station to natural gas and to continue operation of Tracy units 4 and 5 to 2049. Based on this filing, the state of Nevada partially withdrew portions of the State Implementation plan for Regional Haze to re-evaluate emission control measures that may be necessary to achieve reasonable progress during the second implementation period of the Regional Haze Rule in Nevada. In March 2024, the PUCN approved plans to convert the existing coal-fueled North Valmy Generating Station to natural gas and to continue operation of Tracy Units 4 and 5 to 2049 with appropriate emission controls. Following PUCN approval, NV Energy submitted the revised four-factor analysis for Valmy Units 1 and 2 and Tracy Units 4 and 5 to the NDEP. The revised four-factor analysis for Tracy Units 4 and 5 indicated that further reduction of NO_x emissions equivalent to SCR was cost-effective. The revised analysis for Valmy Units 1 and 2 indicated that, following natural gas conversion, further reduction of NO_x emissions equivalent to SNCR was cost-effective. The units may also meet SNCR equivalency with either flue gas recirculation or SCR and SCR may be required if the Good Neighbor Plan is upheld. NDEP finalized regulation in December 2024 to establish legally enforceable NO_x emissions limits at these units for Regional Haze compliance. The state of Nevada expects to submit a revised SIP to the EPA in early 2025, allowing sufficient time for the EPA to act on the plan according to the schedule in the March 2024 consent decree. It is expected that the emissions controls would be required to be installed within 36 months following the EPA approval.

On August 25, 2022, the EPA promulgated a finding of failure to submit a SIP for the regional haze second planning period for 15 states, including Iowa. The finding establishes a two-year deadline for the agency to promulgate FIPs to address the requirements, unless prior to promulgating a FIP, the state submits, and the agency approves, a SIP meeting the requirements. The Iowa Department of Natural Resources issued a SIP in August 2023 that requires operational improvements to existing control equipment at MidAmerican Energy's Louisa Generation Station and Walter Scott, Jr. Energy Center - Unit 3. Iowa submitted that plan to the EPA in fall 2023. The operational improvements were implemented beginning January 1, 2024. On August 2, 2024, the EPA proposed a rule to approve Iowa's SIP as submitted. The EPA accepted comment on the proposal through September 3, 2024. As of the filing date, final action on the SIP has not occurred.

Third Planning Period

On December 23, 2024, the EPA proposed a rule that would change the due date for the next round of SIPS for the third implementation period of the regional haze rule. The current due date is July 31, 2028. The proposed rule would extend the deadline three years, to July 31, 2031. The proposed change has no effect on prior due dates for the second or prior implementation periods under the regional haze rule. The EPA is not proposing to revise the end date for the third implementation period or the start of the fourth implementation period, both of which will occur in 2038. The purpose of the deadline extension is to provide sufficient time for states to incorporate changes to the regional haze rule that the EPA intends to propose. Any action may be subject to further review by the new administration. The EPA accepted comments on the deadline extension proposal through February 6, 2025.

Climate Change

In December 2015, an international agreement was negotiated by 195 nations to create a universal framework for coordinated action on climate change in what is referred to as the Paris Agreement. The Paris Agreement reaffirms the goal of limiting global temperature increase well below 2 degrees Celsius, while urging efforts to limit the increase to 1.5 degrees Celsius and reaching a global peak of GHG emissions as soon as possible to achieve climate neutrality by mid-century; establishes commitments by all parties to make nationally determined contributions and pursue domestic measures aimed at achieving the commitments; commits all countries to submit emissions inventories and report regularly on their emissions and progress made in implementing and achieving their nationally determined commitments; and commits all countries to submit new commitments every five years, with the expectation that the commitments will get more aggressive. In the context of the Paris Agreement, the U.S. agreed to reduce GHG emissions 26% to 28% by 2025 from 2005 levels. After more than 55 countries representing more than 55% of global GHG emissions submitted their ratification documents, the Paris Agreement became effective November 4, 2016; however, the U.S. completed its withdrawal from the Paris Agreement on November 4, 2020. President Biden accepted the terms of the climate agreement on January 20, 2021, and the U.S. completed its reentry February 19, 2021. New commitments to the Paris Agreement were announced in April 2021, with the U.S. pledging to cut its overall GHG emissions 50% to 52% from 2005 levels by 2030 and to reach 100% carbon pollution-free electricity by 2035. In December 2024, President Biden released new commitments to reach a 61% to 66% reduction in emissions by 2035 from 2005 levels, which includes a 35% reduction in methane emissions. President Trump signed an executive order January 20, 2025, directing the U.S. to withdraw from the Paris Agreement, which will be effective a year after formal withdrawal procedures are implemented.

Performance Standards for New and Existing Generating Facilities

In June 2014, the EPA released proposed regulations to address GHG emissions from existing fossil-fueled generating facilities, referred to as the Clean Power Plan, under Section 111(d) of the Clean Air Act. The EPA's proposal calculated state-specific emission rate targets to be achieved based on the "best system of emission reduction." In August 2015, the final Clean Power Plan was released, which established the best system of emission reduction as including: (a) heat rate improvements; (b) increased utilization of existing combined-cycle natural gas-fueled generating facilities; and (c) increased deployment of new and incremental non-carbon generation placed in-service after 2012. The Clean Power Plan was stayed by the U.S. Supreme Court in February 2016. On June 19, 2019, the EPA repealed the Clean Power Plan and issued the Affordable Clean Energy rule. In the Affordable Clean Energy rule, the EPA determined that the best system of emission reduction for existing coal-fueled generating facilities is limited to actions that result in heat rate improvements at individual units. On January 19, 2021, the D.C. Circuit vacated and remanded the Affordable Clean Energy rule to the EPA, finding that the rule "rested critically on a mistaken reading of the Clean Air Act" that limited the best system of emission reduction to actions taken at a facility. In October 2021, the U.S. Supreme Court agreed to hear an appeal of that decision. The U.S. Supreme Court issued its decision regarding the scope of the EPA's authority to regulate greenhouse gas emissions under the Clean Air Act in June 2022. The U.S. Supreme Court held that the "generation shifting" approach in the Clean Power Plan exceeded the powers granted to the EPA by Congress, although the court did not address whether the EPA may only adopt measures applied at the individual source as it did in the Affordable Clean Energy rule. A key area where the EPA went astray was using the Clean Power Plan to give states the option to promulgate regulations that would encourage "generation shifting," or moving away from higher-polluting power sources like coal to lower-polluting sources like natural gas or renewables. The U.S. Supreme Court reversed the D.C. Circuit's vacatur of the Affordable Clean Energy rule and remanded the case for further proceedings. In May 2023, the EPA proposed rules addressing greenhouse gas emissions from new and reconstructed natural gas-fueled combustion turbines (Clean Air Act Section 111(b) rule) and existing coal- and gas- or oil-fueled steam units and natural gas-fueled combustion turbines (Clean Air Act Section 111(d) rule). On April 25, 2024, the EPA finalized rules setting greenhouse gas emissions standards for new natural gas-fueled combustion turbines and existing coal-, gas- and oil-fueled steam units. The EPA deferred action on emissions standards for existing natural gas-fueled combustion turbines. New natural gas-fueled combustion turbines are expected to utilize lower-emitting fuels and operate as highly efficient generation. Additionally, new baseload combustion turbines exceeding a 40% annual capacity factor must meet an emission limit equivalent to operating with carbon capture and sequestration beginning January 1, 2032. The EPA identified carbon capture and sequestration as the technology basis for the emissions standards for coal units. Coal-fueled units that will operate after December 31, 2038, must meet emission limits equivalent to operating with carbon capture and sequestration beginning January 1, 2032. Other units are anticipated to co-fire with natural gas and retire prior to January 1, 2039 or convert to natural gas operations and meeting emission limits corresponding to capacity factors. Emission limits for individual generating units must be specified in state compliance plans, which must be submitted to the EPA within 24 months of the rule's publication in the Federal Register. Facilities are not required to retrofit with carbon capture technology but must meet emission limits based on the technology. PacifiCorp operates nine coal-fueled units and MidAmerican Energy operates six coal-fueled units that are currently not planned for retirement or conversion to natural gas operations by 2032, when the emissions standards would take effect. NV Energy operates one natural gas-fueled unit subject to limits for new sources. The relevant Registrants continue to evaluate the rule and business plans to identify flexible compliance mechanisms that minimize costs while assuring the delivery of safe and reliable energy to customers. Litigation challenging the final rules was filed the same day they were published. The D.C. Circuit denied motions to stay the rules July 19, 2024, concluding the measure is not a "major question" requiring higher judicial scrutiny and that critics have not shown they will succeed on the merits of their claims. In addition, a three-judge panel of the court downplayed any "irreparable harm" that opponents of the rule would face while the litigation plays out. The court set an expedited briefing schedule in order to hear oral arguments in fall 2024. Emergency petitions to stay the rules were quickly filed with the U.S. Supreme Court. On October 16, 2024, the U.S. Supreme Court denied petitions to stay the rule, concluding that applicants would not suffer irreparable harm since the case before the D.C. Circuit is proceeding on an expedited schedule. The D.C. Circuit subsequently heard arguments in the case December 6, 2024. On February 5, 2025, the EPA filed a motion requesting abeyance of litigation and asking the D.C. Circuit to withhold issuing its decision in the case. The D.C. Circuit granted the motion February 19, 2025, and directed the EPA to file a motion by April 21, 2025, to govern further proceedings in the case. Until further rulemaking and litigation is exhausted, the relevant Registrants cannot determine the full impacts of the final rule.

New Source Performance Standards for Methane Emissions

In August 2020, the EPA finalized regulations to rescind standards for methane emissions from the oil and gas sector. The changes eliminate requirements to regulate methane emissions from the production, processing, transmission and storage of oil and gas. The rule was immediately challenged by environmental and tribal groups, as well as numerous states. In January 2021, the D.C. Circuit lifted an administrative stay and allowed the rule to take effect, finding that groups challenging the rule had not met the standard for a long-term stay. On June 30, 2021, President Biden signed into law a joint resolution of Congress, adopted under the Congressional Review Act, disapproving the August 2020 rule. The resolution reinstated the 2012 volatile organic compounds standards and the 2016 volatile organic compounds and methane standards for the oil and natural gas transmission and storage segments, as well as the methane standards for the production and processing segments of the oil and gas sector. On November 2, 2021, the EPA proposed rules that would reduce methane emissions from both new and existing sources in the oil and natural gas industry. The proposals would expand and strengthen emission reduction requirements for new, modified and reconstructed oil and natural gas sources and would require states to reduce methane emissions from existing sources nationwide. The EPA issued a supplemental proposal in November 2022 to further strengthen emission reduction requirements. The EPA issued the final rule in December 2023, establishing emissions standards and leak detection and repair requirements for a number of components across the natural gas system. Kern River is not affected by the rule. Northern Natural Gas and BHE GT&S are affected by the rule and anticipate replacing some pneumatic controllers at compressor stations and seals at centrifugal and reciprocating compressors. Additional leak detection and repair surveys and reports are also anticipated. States and industry groups are challenging the rule at the D.C. Circuit. Both the D.C. Circuit and the U.S. Supreme Court have denied petitions to stay the rule during litigation. Until litigation is exhausted, the relevant Registrants cannot determine the full impacts of the final rule.

In January 2024, the EPA proposed the methane fee rule, which is required under the Inflation Reduction Act. The fee, called a waste emissions charge, will be assessed on natural gas facilities that are subject to Greenhouse Gas Reporting Program Subpart W reporting. For transmission and storage operations, any facility that reports methane emissions over the congressionally-determined "0.11% of the methane sent to sale from or through such facility" will pay a fee to the federal government. The fee can be reduced by the netting of emissions, or altogether eliminated by certain statutory exemptions. The amount of the fee is scaled, beginning at \$900 per metric ton of methane over the 0.11% threshold beginning in 2025 and increasing to \$1,500 per metric ton of methane over the 0.11% threshold in 2027. The EPA issued the final Waste Emissions Charge on November 12, 2024. The relevant Registrants do not expect significant impacts from the rule due to the combination of the excess emissions threshold, netting allowance and compliance with the methane emissions standards rule.

Water Quality Standards

In November 2015, the EPA published final effluent limitation guidelines and standards for the steam electric power generating sector which, among other things, regulate the discharge of bottom ash transport water, fly ash transport water, combustion residual leachate and non-chemical metal cleaning wastes. In November 2019, the EPA proposed updates to the 2015 rule, specifically addressing flue gas desulfurization wastewater and bottom ash transport water. The rule took effect in December 2020. The final rule changes the technology-basis for treatment of flue gas desulfurization wastewater and bottom ash transport water, revises the voluntary incentives program for flue gas desulfurization wastewater, and adds subcategories for high-flow units, low utilization units, and those that will transition away from coal combustion by 2028. While most of the issues raised by this rule are already being addressed through the CCR rule and are not expected to impose significant additional requirements, the Dave Johnston generating facility is impacted by the rule's bottom ash handling requirements at Units 1 and 2. The generating facility submitted notice to the Wyoming Department of Environmental Quality that it will either achieve a cessation of coal combustion at Units 1 and 2 by December 31, 2028, or install bottom ash transport treatment technology by December 31, 2025. On April 25, 2024, the EPA finalized additional changes to the effluent limitations guidelines to replace the 2020 rule and provide stricter limits for bottom ash transport water, flue gas desulfurization wastewater and coal combustion residual leachate. The relevant Registrants use a combination of zero discharge, enrollment in cessation-of-coal subcategory and dry bottom ash handling to manage the affected wastestreams. As a result, significant impacts are not anticipated.

Coal Ash Disposal

In April 2015, the EPA released a final rule to regulate the management and disposal of coal combustion residuals (CCR) under the RCRA. The rule regulates coal combustion residuals as non-hazardous waste under RCRA Subtitle D and establishes minimum nationwide standards for the disposal of CCR. Under the final rule, surface impoundments and landfills utilized for coal combustion residuals will need to be closed unless they can meet the more stringent regulatory requirements.

At the time the rule was published in April 2015, PacifiCorp operated 18 surface impoundments and seven landfills that contained coal combustion residuals. Prior to the effective date of the rule in October 2015, nine surface impoundments and three landfills were either closed or repurposed to no longer receive coal combustion residuals and hence are not subject to the final rule. As PacifiCorp proceeded to implement the final coal combustion rule, it was determined that two surface impoundments located at the Dave Johnston generating facility were hydraulically connected and effectively constitute a single impoundment. In November 2017, a new surface impoundment was placed into service at the Naughton Generating Station. In October 2023, a new surface impoundment was placed into service at the Jim Bridger facility. At the time the rule was published in April 2015, MidAmerican Energy owned or operated nine surface impoundments and four landfills that contained coal combustion residuals. Prior to the effective date of the rule in October 2015, MidAmerican Energy closed or repurposed six surface impoundments to no longer receive coal combustion residuals. As of July 10, 2024, all of the surface impoundments have been closed. At the time the rule was published in April 2015, the Nevada Utilities operated 10 evaporative surface impoundments and two landfills that contained coal combustion residuals. Prior to the effective date of the rule in October 2015, the Nevada Utilities closed four of the surface impoundments, four impoundments discontinued receipt of coal combustion residuals making them inactive and two surface impoundments remain active and subject to the final rule. The two landfills remain active and subject to the final rule.

On April 25, 2024, the EPA finalized the legacy surface impoundments rule to extend federal CCR regulatory requirements to (1) inactive CCR surface impoundments at inactive utilities and (2) CCR management units ("CCRMU") at active facilities, including CCR impoundments and landfills that closed prior to the effective date of the 2015 CCR Rule, inactive CCR landfills, and other areas where CCR is managed directly on the land. The final rule includes exemptions and establishes new categories where regulation is deferred for applicable units, including CCRMU containing less than 1,000 tons of CCR, CCRMU located beneath critical infrastructure or large buildings or structures vital to the continuation of current site activities, and CCRMU that were closed prior to the effective date of the new rule. The EPA also finalized one outstanding item from the Part B Proposal in the final legacy CCR rule: the additional closure option for CCR units being closed by removal of CCR such that impacts to groundwater can be remediated after closure of the CCR unit is complete. Affected active facilities must conduct a facility evaluation and report to determine the presence of CCRMUs. The first phase of the facility evaluation is due February 9, 2026, and the second phase is due February 8, 2027. In addition, groundwater monitoring must be initiated within 48 months and closure must be initiated within 60 months of the rule's publication in the Federal Register. Affected inactive facilities must complete an applicability report by November 8, 2024, to determine the presence of legacy surface impoundments. The relevant Registrants did not identify any legacy surface impoundments subject to the rule. The relevant Registrants have commenced the facility evaluation requirements for certain CCRMUs subject to the rule. The City Utilities of Springfield, Missouri and other parties challenged the legacy surface impoundments rule in June 2024. On February 13, 2025, the EPA filed a motion requesting abeyance of litigation for 120 days to allow a transition to the new administration. The D.C. Circuit granted the request for abeyance and directed the EPA to file a motion to govern further proceedings by June 13, 2025. Until litigation is exhausted, the relevant Registrants cannot assess the full impacts of the rule at this time.

The EPA has previously proposed additional amendments to the CCR rule, including a federal permit program, the "Part B, Part 2" rule, and a beneficial use rulemaking.

Until the outstanding proposals are finalized and fully litigated, the Registrants cannot determine whether additional action may be required.

Notwithstanding the status of the final CCR rule, citizens' suits have been filed against regulated entities seeking judicial relief for contamination alleged to have been caused by releases of coal combustion residuals. Some of these cases have been successful in imposing liability upon companies if coal combustion residuals contaminate groundwater that is ultimately released or connected to surface water. In addition, actions have been filed against regulated entities seeking to require that surface impoundments containing CCR be subject to closure by removal rather than being allowed to effectuate closure in place as provided under the final rule. The Registrants are not a party to these lawsuits and until they are resolved, the Registrants cannot predict the impact on overall compliance obligations.

Separately, on June 28, 2024, the D.C. Circuit issued a decision dismissing industry challenges to both the EPA's January 11, 2022, actions and interpretations related to the closure performance standards in the 2015 CCR rule and the EPA's November 28, 2022, final Part A denial for the Gavin Power Station based, in part, on those interpretations. The court ruled that the challenged actions do not amount to the kind of agency action promulgating a regulation or requirement that the court has jurisdiction to review under the Resource Conservation and Recovery Act. As a result, the court dismissed the petitions for lack of jurisdiction and clarified that EPA's actions were straightforward applications of the rule. The challenged actions concerned the EPA's determinations that (1) operators cannot close surface impoundments with groundwater leaching in and out of the unit; (2) groundwater becomes a "free liquid" as it makes its way into a coal combustion residual unit when assessing the "eliminate free liquids" performance standard; and (3) operators must minimize infiltration of liquids, including groundwater, from all directions to satisfy the infiltration performance standard. The relevant Registrants continue to review the court's decision to assess whether previously closed surface impoundments are impacted.

Other

Other laws, regulations and agencies to which the relevant Registrants are subject include, but are not limited to:

- The federal Comprehensive Environmental Response, Compensation and Liability Act and similar state laws may require any current or former owners or operators of a disposal site, as well as transporters or generators of hazardous substances sent to such disposal site, to share in environmental remediation costs. Certain Registrants have been identified as potentially responsible parties in connection with certain disposal sites. The relevant Registrants have completed several cleanup actions and are participating in ongoing investigations and remedial actions. Costs associated with these actions are not expected to be material and are expected to be found prudent and included in rates.
- The Nuclear Waste Policy Act of 1982, under which the DOE is responsible for the selection and development of repositories for, and the permanent disposal of, spent nuclear fuel and high-level radioactive wastes. Refer to Note 14 of the Notes to Consolidated Financial Statements of Berkshire Hathaway Energy in Item 8 of this Form 10-K and Note 11 of the Notes to Financial Statements of MidAmerican Energy in Item 8 of this Form 10-K for additional information regarding MidAmerican Energy's nuclear decommissioning obligations.
- The federal Surface Mining Control and Reclamation Act of 1977 and similar state statutes establish operational, reclamation and closure standards that must be met during and upon completion of PacifiCorp's mining activities.
- The FERC evaluates hydroelectric systems to ensure environmental impacts are minimized, including the issuance of environmental impact statements for licensed projects both initially and upon relicensing. The FERC monitors the hydroelectric facilities for compliance with the license terms and conditions, which include environmental provisions. Refer to Note 16 of the Notes to Consolidated Financial Statements of Berkshire Hathaway Energy in Item 8 of this Form 10-K and Note 14 of the Notes to Consolidated Financial Statements of PacifiCorp in Item 8 of this Form 10-K for information regarding PacifiCorp's Klamath River hydroelectric system.

The Registrants expect they will be allowed to recover their respective prudently incurred costs to comply with the environmental laws and regulations discussed above. The Registrants' planning efforts take into consideration the complexity of balancing factors such as: (a) pending environmental regulations and requirements to reduce emissions, address waste disposal, ensure water quality and protect wildlife; (b) avoidance of excessive reliance on any one generation technology; (c) costs and trade-offs of various resource options including energy efficiency, demand response programs and renewable generation; (d) state-specific energy policies, resource preferences and economic development efforts; (e) additional transmission investment to reduce power costs and increase efficiency and reliability of the integrated transmission system; and (f) keeping rates affordable. Due to the number of generating units impacted by environmental regulations, deferring installation of compliance-related projects is often not feasible or cost effective and places the Registrants at risk of not having access to necessary capital, material, and labor while attempting to perform major equipment installations in a compressed timeframe concurrent with other utilities across the country. Therefore, the Registrants have established installation schedules with permitting agencies that coordinate compliance timeframes with construction and tie-in of major environmental compliance projects as units are scheduled off-line for planned maintenance outages; these coordinated efforts help reduce costs associated with replacement power and maintain system reliability.

Item 1A. Risk Factors

Each Registrant is subject to numerous risks and uncertainties, including, but not limited to, those described below. Careful consideration of these risks, together with all of the other information included in this Form 10-K and the other public information filed by the relevant Registrant, should be made before making an investment decision. Additional risks and uncertainties not presently known or which each Registrant currently deems immaterial may also impair its business operations. Unless stated otherwise, the risks described below generally relate to each Registrant.

Liquidity, Capital Requirements and Corporate Structure Risks

BHE and EEGH are holding companies and depend on distributions from subsidiaries, including joint ventures, to meet their obligations.

BHE and EEGH are holding companies with no material assets other than the investment interests in their subsidiaries and joint ventures, collectively referred to as subsidiaries. Accordingly, the cash flows of BHE and EEGH and the ability to meet their obligations are largely dependent upon the earnings of their respective subsidiaries and the payment of such earnings to BHE or EEGH in the form of dividends or other distributions. As a result of material wildfire litigation at PacifiCorp, no dividends will be paid to BHE by PacifiCorp over the next several years, which could impact BHE's ability to fund its operations, make interest payments, fund debt maturities and increase BHE's reliance on debt.

Prior to funding the obligations of BHE or EEGH, their respective subsidiaries, including the Subsidiary Registrants, have financial obligations and certain regulatory restrictions that must be satisfied. Each respective subsidiary is a separate and distinct legal entity and has no obligation, contingent or otherwise, to pay amounts due pursuant to BHE's or EEGH's debt or other obligations, or to make funds available, whether by dividends or other payments, for the payment of amounts due pursuant to BHE's or EEGH's debt or other obligations, and do not guarantee the payment of any of BHE's or EEGH's obligations. Distributions from subsidiaries may also be limited by:

- PacifiCorp's liquidity concerns resulting from wildfire litigation (described below);
- their respective earnings, capital requirements, and required debt payments;
- the satisfaction of certain terms contained in financing, ring-fencing or organizational documents; and
- regulatory restrictions that limit the ability of BHE's regulated utility subsidiaries to distribute profits.

The Registrants are substantially leveraged, the terms of their existing debt do not restrict the incurrence of additional debt by BHE or its subsidiaries, including the Subsidiary Registrants, and BHE's debt is structurally subordinated to the debt of its subsidiaries, including the Subsidiary Registrants, and each of such factors could adversely affect the Registrants' financial results.

A significant portion of BHE's capital structure is comprised of debt, and BHE expects to incur additional debt in the future to fund items such as, among others, acquisitions, capital investments and the development and construction of new or expanded facilities. As of December 31, 2024, BHE had the following outstanding obligations:

- senior unsecured debt of \$13.1 billion;
- guarantees, letters of credit and surety bonds in respect of subsidiaries, equity method investments and other related parties aggregating \$3.5 billion; and

BHE's consolidated subsidiaries, including the Subsidiary Registrants, also have significant amounts of outstanding debt, which totaled \$43.1 billion as of December 31, 2024, and expect to incur additional debt in the future to fund items such as, among others, acquisitions, capital investments and the development and construction of new or expanded facilities. These amounts exclude (a) trade debt, (b) preferred stock obligations, (c) letters of credit in respect of subsidiary debt, and (d) BHE's share of the outstanding debt of its own or its subsidiaries' equity method investments.

Given each Registrant's substantial leverage, it may not have sufficient cash to service its debt, which could limit its ability to finance future acquisitions, develop and construct additional projects, or operate successfully under difficult conditions, including those brought on by adverse national and global economies, unfavorable financial markets or growth conditions where its capital needs may exceed its ability to fund them. Each Registrant's leverage could also impair its credit quality or the credit quality of its subsidiaries, making it more difficult to finance operations or issue future debt on favorable terms, and could result in a downgrade in debt ratings by credit rating agencies.

The terms of BHE's and its subsidiaries' debt, including the Subsidiary Registrants, do not limit BHE's ability or the ability of its subsidiaries to incur additional debt or issue preferred stock. Accordingly, BHE or its subsidiaries could enter into acquisitions, new financings, refinancings, recapitalizations, leases or other highly leveraged transactions that could significantly increase BHE's or its subsidiaries' total amount of outstanding debt. The interest payments needed to service this increased level of debt could adversely affect BHE's or its subsidiaries' financial results. Many of BHE's subsidiaries' debt agreements contain covenants, or may in the future contain covenants, that restrict or limit, among other things, such subsidiaries' ability to create liens, sell assets, make certain distributions, incur additional debt or miss contractual deadlines or requirements, and BHE's ability to comply with these covenants may be affected by events beyond its control. Further, if an event of default accelerates a repayment obligation and such acceleration results in an event of default under some or all of BHE's other debt, BHE may not have sufficient funds to repay all of the accelerated debt simultaneously, and the other risks described under "Corporate and Financial Structure Risks" may be magnified as well.

Because BHE is a holding company, the claims of its debt holders are structurally subordinated with respect to the assets and earnings of its subsidiaries. Therefore, the rights of its creditors to participate in the assets of any subsidiary in the event of a liquidation or reorganization are subject to the prior claims of the subsidiary's creditors and preferred shareholders, if any. In the event of default due to the bankruptcy, insolvency, or reorganization of a significant subsidiary, all of BHE's debt will become immediately due. In addition, pursuant to separate financing agreements, substantially all of PacifiCorp's electric utility properties, MidAmerican Energy's electric utility properties in the state of Iowa, Nevada Power's and Sierra Pacific's properties in the state of Nevada, AltaLink's transmission properties, the equity interest of MidAmerican Funding's subsidiary and substantially all of the assets of the subsidiaries of BHE Renewables that are direct or indirect owners of solar and wind generation projects, are directly or indirectly pledged to secure their financings and, therefore, may be unavailable as potential sources of repayment of BHE's debt.

A downgrade in BHE's credit ratings or the credit ratings of its subsidiaries, including the Subsidiary Registrants, could negatively affect BHE's or its subsidiaries' access to capital, increase the cost of borrowing or raise energy transaction credit support requirements and PacifiCorp's credit rating has been downgraded as a result of wildfire litigation related risks.

BHE's senior unsecured debt and its subsidiaries' long-term debt, including the Subsidiary Registrants, are rated by various rating agencies. BHE cannot give assurance that its senior unsecured debt rating or any of its subsidiaries' long-term debt ratings will not be reduced in the future. Although none of the Registrants' outstanding debt has rating-downgrade triggers that would accelerate a repayment obligation, a credit rating downgrade would increase any such Registrant's borrowing costs and commitment fees on its revolving credit agreements and other financing arrangements, perhaps significantly. In addition, such Registrant would likely be required to pay a higher interest rate in future financings, the potential pool of investors would likely decrease and depending on the rating, require some investors to sell the Registrants' bonds. Further, access to the commercial paper market could be significantly limited, resulting in higher interest costs.

Similarly, any downgrade, change in rating methodology impacting subsidiaries credit rating, placement on negative outlook or credit watch or other event negatively affecting the credit ratings of BHE's subsidiaries could make their costs of borrowing higher or access to funding sources more limited, which in turn could cause BHE to provide liquidity in the form of capital contributions or loans to such subsidiaries, thus reducing its and its subsidiaries' liquidity and borrowing capacity; however BHE is not obligated to provide liquidity to its subsidiaries.

Most of the Registrants' large wholesale customers, suppliers and counterparties require such Registrant to have sufficient creditworthiness in order to enter into transactions, particularly in the wholesale energy markets. If the credit ratings of a Registrant were to decline, especially below investment grade, the relevant Registrant's financing costs and borrowings would likely increase because certain counterparties may require collateral in the form of cash, a letter of credit or some other form of security for existing transactions and as a condition to entering into future transactions with such Registrant. Amounts could be material and could adversely affect such Registrant's liquidity and cash flows.

Refer to "PacifiCorp Wildfire Litigation Risks" section below for additional information regarding PacifiCorp.

Disruptions in the financial markets could affect each Registrant's ability to obtain debt financing or to draw upon or renew existing credit facilities and have other adverse effects on each Registrant.

Disruptions in the financial markets could affect each Registrant's ability to obtain debt financing or to draw upon or renew existing credit facilities and have other adverse effects on each Registrant. Significant dislocations and liquidity disruptions in the U.S., Great Britain, Canada and global credit markets, such as those that occurred in 2008, 2009 and 2020, may materially impact liquidity in the bank and debt capital markets, making financing terms less attractive for borrowers that are able to find financing and, in other cases, may cause certain types of debt financing, or any financing, to be unavailable. Additionally,

economic uncertainty in the U.S. or globally may adversely affect the U.S. credit markets and could negatively impact each Registrant's ability to access funds on favorable terms or at all. If a Registrant is unable to access the bank and debt markets to meet liquidity and capital expenditure needs, it may adversely affect the timing and amount of its capital expenditures, acquisition financing and its financial results.

Poor performance of plan and fund investments and other factors impacting the pension and other postretirement benefit plans and nuclear decommissioning and mine reclamation trust funds could unfavorably impact each Registrant's cash flows, liquidity and financial results.

Costs of providing each Registrant's defined benefit pension and other postretirement benefit plans and costs associated with the joint trustee plan to which PacifiCorp contributes depend upon a number of factors, including the rates of return on plan assets, the level and nature of benefits provided, discount rates, mortality assumptions, the interest rates used to measure required minimum funding levels, the funded status of the plans, changes in benefit design, tax deductibility and funding limits, changes in laws and government regulation and each Registrant's required or voluntary contributions made to the plans. Furthermore, the timing of recognition of unrecognized gains and losses associated with the Registrants' defined benefit pension plans is subject to volatility due to events that may give rise to settlement accounting. Settlement events resulting from lump sum distributions offered by certain of the Registrants' defined benefit pension plans are influenced by the interest rates used to discount a participant's lump sum distribution. When the applicable interest rates are low, lump sum distributions in a given year tend to increase resulting in a higher likelihood of triggering settlement accounting.

If the Registrant's pension or other postretirement benefit plans are in underfunded positions, the respective Registrant may be required to make cash contributions to fund such underfunded plans in the future. Additionally, each Registrant's plans have investments in domestic and foreign equity and debt securities and other investments that are subject to the risk of loss. Losses from investments could add to the volatility, size and timing of future contributions.

Furthermore, the funded status of the UMWA 1974 Pension Plan multiemployer plan to which PacifiCorp's subsidiary previously contributed is considered critical and declining. PacifiCorp's subsidiary involuntarily withdrew from the UMWA 1974 Pension Plan in June 2015 when the UMWA employees ceased performing work for the subsidiary. PacifiCorp has recorded its best estimate of the withdrawal obligation.

In addition, MidAmerican Energy is required to fund over time the projected costs of decommissioning Quad Cities Station, a nuclear generating facility, and Bridger Coal Company, a joint venture of PacifiCorp's subsidiary, Pacific Minerals, Inc., is required to fund projected mine reclamation costs. The funds that MidAmerican Energy has invested in a nuclear decommissioning trust and a subsidiary of PacifiCorp has invested in a mine reclamation trust are invested in debt and equity securities and poor performance of these investments will reduce the amount of funds available for their intended purpose, which could require MidAmerican Energy or PacifiCorp's subsidiary to make additional cash contributions. As contributions to the trust are being made over the operating life of the respective facility, reductions in the expected operating life of the facility could also require MidAmerican Energy and PacifiCorp's subsidiary to make additional contributions to the related trust. Such cash funding obligations, which are also impacted by the other factors described above, could have a material impact on MidAmerican Energy's or PacifiCorp's liquidity by reducing their available cash. Additionally, PacifiCorp's mine reclamation obligation for Bridger Coal Company is secured by a surety bond. Refer to "PacifiCorp Wildfire Litigation and Insurance Risks" above for additional information regarding the impact of wildfire litigation risks on PacifiCorp's liquidity and ability to obtain security.

BHE's shareholder, Berkshire Hathaway, could exercise control over BHE in a manner that would benefit Berkshire Hathaway to the detriment of BHE's creditors and BHE could exercise control over the Subsidiary Registrants in a manner that would benefit BHE to the detriment of the Subsidiary Registrants' creditors.

Berkshire Hathaway holds all of the common stock of BHE and has control over all decisions requiring shareholder approval. In circumstances involving a conflict of interest between Berkshire Hathaway and BHE's creditors, Berkshire Hathaway could exercise its control in a manner that would benefit Berkshire Hathaway to the detriment of BHE's creditors.

BHE indirectly holds all of the common stock of PacifiCorp, Nevada Power, Sierra Pacific and EGTS and the membership interest in Eastern Energy Gas. BHE is also the sole member of MidAmerican Funding and, accordingly, indirectly holds all of MidAmerican Energy's common stock. As a result, BHE has control over all decisions requiring shareholder approval, including the election of directors. In circumstances involving a conflict of interest between BHE and the creditors of the Subsidiary Registrants, BHE could exercise its control in a manner that would benefit BHE to the detriment of the Subsidiary Registrants' creditors.

PacifiCorp Wildfire Risks

PacifiCorp's litigation risk associated with the Wildfires is inherently uncertain and the ultimate outcomes of the associated claims could materially and adversely affect PacifiCorp's financial condition and results of operations and its ability to obtain financing, to fund its operations, capital investments and settlements arising from the Wildfires, and to obtain and fund third-party liability insurance coverage.

Litigation

In September 2020, a severe weather event resulting in high winds, low humidity and warm temperatures contributed to several major wildfires, private and public property damages, personal injuries and loss of life and widespread power outages in Oregon and Northern California. Additionally, a major wildfire began in PacifiCorp's service territory in July 2022 causing private and public property damage, personal injuries, loss of life and power outages in Northern California.

A significant number of complaints and demands alleging similar claims related to the 2020 Wildfires have been filed in Oregon and California, including a class action complaint. Additionally, multiple complaints associated with the 2022 McKinney Fire have been filed in California. Refer to Item 3. Legal Proceedings, BHE's Note 16 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K and PacifiCorp's Note 14 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information on the Wildfires. PacifiCorp may be subject to additional complaints and demands (collectively "actions") associated with the Wildfires. Further, the amounts specified in the original filed actions do not limit the amount of damages that ultimately may be awarded in a court proceeding, and therefore PacifiCorp's liability for damages could be substantially greater than the original amounts specified and its estimated losses. For example, plaintiffs frequently are permitted to amend their complaints, such as to seek punitive and additional noneconomic damages. While certain settlements have occurred, PacifiCorp cannot be certain that additional settlements can be achieved on terms it finds reasonable, if at all.

As described in BHE's Note 16 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K and PacifiCorp's Note 14 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K, the jury in an initial June 2023 trial related to the 2020 Wildfires (captioned Jeanyne James et al. v. PacifiCorp et al, in Multnomah County Circuit Court, Oregon, and referred to as "*James*") issued a verdict finding PacifiCorp liable to the 17 individual plaintiffs and making certain findings as to the class with respect to four wildfires. While PacifiCorp disagrees with and has appealed the court's granting of class certification (among other matters), the potential class size, if class certification is not overturned on appeal, could be significant and the liability for damages may be substantially higher than current estimated losses. Additional trials related to the Wildfires, including damages-only trials for *James*, are expected and could also result in an increase in current estimated losses. Damages with respect to certain plaintiffs may be significantly higher or lower than with respect to other plaintiffs. PacifiCorp intends to appeal adverse decisions, starting with the *James* decisions, such that it is possible that a final determination of its liability and damages could take several years.

Liquidity

As a result of the litigation risk and estimated losses recorded to date associated with the Wildfires, PacifiCorp's liquidity has been materially impacted and its credit ratings have been downgraded. PacifiCorp could experience further declines in its credit ratings, changes to its ratings methodology, placed on credit watch or outlook negative if additional unfavorable litigation or similar outcomes occur as a result of the Wildfires.

These changes in PacifiCorp's credit ratings have and are expected to continue to have a material impact on PacifiCorp's liquidity and may result in, among other things, PacifiCorp being unable to maintain sufficient levels of cash or to obtain necessary short- and long-term financing to fund its operations and financial obligations, capital investments and potential future settlements associated with the Wildfires. PacifiCorp may be unable to access debt capital markets for an extended period of time in the event of unfavorable jury verdicts, additional declines in PacifiCorp's credit ratings and potential uncertainty around PacifiCorp's ultimate exposure associated with the *James* class action and future catastrophic wildfires that may occur despite PacifiCorp's wildfire mitigation efforts. PacifiCorp may also be subject to borrowing limitations due to long-term debt covenants and increasing leverage ratios. Furthermore, investors in PacifiCorp's first mortgage bonds may be unable to hold existing bonds or to invest in new bonds, and perceived risks associated with the Wildfires may limit PacifiCorp's ability to attract investors. At a minimum, the cost of any short- or long-term financing is expected to be higher as a result of the wildfire litigation risks and decline in PacifiCorp's credit ratings.

In addition to the above-described financing constraints, PacifiCorp may be required to provide additional collateral, letters of credit, adequate assurance, or other forms of security to achieve otherwise routine transactions and at a higher cost than has

been experienced in the past. Collateral may be required to be posted in association with commodity contracts with credit-risk-related contingent features or material adverse change clauses.

Refer to Item 7 "Liquidity and Capital Resources" for further information regarding the liquidity impacts arising from the Wildfires.

Insurance

PacifiCorp has experienced material increases in the cost of third-party liability insurance as a result of worsening damage claims in the utility industry associated with catastrophic wildfires in the geographic regions in which PacifiCorp operates. Such costs may continue to increase materially to the point of being prohibitively expensive, and it is possible that PacifiCorp may be unable to obtain third-party liability insurance. Increases in the cost of insurance may be challenged when PacifiCorp seeks cost recovery and such amounts may not be recoverable in customer rates. To the extent third-party liability insurance costs continue to increase, becomes cost prohibitive or is unavailable and such increased costs are not recoverable in customer rates, PacifiCorp's financial condition and results of operations could be materially adversely affected and its liquidity position further negatively impacted.

Regulatory, Legislative and Legal Risks

Each Registrant may be subject to extensive federal, state, local and foreign legislation and regulation, including numerous environmental, health, safety, reliability, data privacy and other laws and regulations that may affect its operations and costs. These laws and regulations are complex, dynamic and subject to new interpretations or change. In addition, new laws and regulations, including, but not limited to, initiatives regarding deregulation and restructuring of the utility industry, are continually being proposed and enacted that may impose new or revised requirements or standards on each Registrant.

Each Registrant is required to comply with numerous federal, state, local or foreign laws and regulations as described in "General Regulation" and "Environmental Laws and Regulations" in Item 1 of this Form 10-K that have broad application to each Registrant and limits the respective Registrant's ability to independently make and implement management decisions regarding, among other items, acquiring businesses; constructing, acquiring, disposing or retiring operating assets; operating and maintaining generating facilities and transmission and distribution system assets; complying with pipeline safety and integrity and environmental requirements; setting rates charged to customers; establishing capital structures and issuing debt or equity securities; managing and reporting transactions between subsidiaries and affiliates; and paying dividends or similar distributions. These laws and regulations, which are followed in developing the Registrants' safety and compliance programs and procedures, are implemented and enforced by federal, state and local regulatory agencies, such as the Occupational Safety and Health Administration, the FERC, the EPA, the DOT, the NRC, the Federal Mine Safety and Health Administration and various state regulatory commissions in the U.S., and by foreign regulatory agencies, such as GEMA, which discharges certain of its powers through its staff within Ofgem, in Great Britain and the AUC in Alberta, Canada.

Compliance with applicable laws and regulations generally requires each Registrant to obtain and comply with a wide variety of licenses, permits, inspections, audits and other approvals. Further, compliance with laws and regulations can require significant capital and operating expenditures, including expenditures for new equipment, inspection, cleanup costs, removal and remediation costs and damages arising out of contaminated properties. Compliance activities pursuant to existing or new laws and regulations could be prohibitively expensive or otherwise uneconomical. As a result, each Registrant could be required to shut down some facilities or materially alter its operations. Further, each Registrant may not be able to obtain or maintain all required environmental or other regulatory approvals and permits for its operating assets or development projects. Delays in, or active opposition by third parties to, obtaining any required environmental or regulatory authorizations or failure to comply with the terms and conditions of the authorizations may increase costs or prevent or delay each Registrant from operating its facilities, developing or favorably locating new facilities or expanding existing facilities. If any Registrant fails to comply with any environmental or other regulatory requirements, such Registrant may be subject to penalties and fines or other sanctions, including changes to the way its electricity generating facilities are operated that may adversely impact generation or how the Pipeline Companies are permitted to operate their systems that may adversely impact throughput. The costs of complying with laws and regulations could adversely affect each Registrant's financial results. Not being able to operate existing facilities or develop new generating facilities to meet customer electricity needs could require such Registrant to increase its purchases of electricity on the wholesale market, which could increase market and price risks and adversely affect such Registrant's financial results.

Existing laws and regulations, while comprehensive, are subject to changes and revisions from ongoing policy initiatives by legislators and regulators and to interpretations that may ultimately be resolved by the courts. For example, changes in laws and regulations could result in, but are not limited to, increased competition and decreased revenue within each Registrant's service

territories; new environmental or climate-related requirements; RPS and GHG emissions reduction goals; the issuance of new or stricter air quality standards; the implementation of energy efficiency mandates; the issuance of regulations governing the management and disposal of coal combustion byproducts; changes in forecasting requirements; changes to each Registrant's service territories as a result of condemnation or takeover by municipalities or other governmental entities, particularly where it lacks the exclusive right to serve its customers; the inability of each Registrant to recover its costs on a timely basis, if at all; new pipeline safety requirements; or a negative impact on each Registrant's current cost recovery arrangements. In addition to changes in existing legislation and regulation, new laws and regulations are likely to be enacted from time to time that impose additional or new requirements or standards on each Registrant. Adverse rulings in GHG-related cases could result in increased or changed regulations and could increase costs for GHG emitters, including the Registrants' generating facilities. The GHG rules, changes to those rules, and the Registrants' compliance requirements are subject to potential outcomes from proceedings and litigation challenging the rules.

New federal, regional, state and international accords, legislation, regulation, or judicial proceedings limiting GHG emissions could have a material adverse impact on the Registrants, the U.S. and the global economy. Companies and industries with higher GHG emissions, such as utilities with significant coal-fueled generating facilities, will be subject to more direct impacts and greater financial and regulatory risks. The impact is dependent on numerous factors, none of which can be meaningfully quantified at this time. These factors include, but are not limited to, the magnitude and timing of GHG emissions reduction requirements; the design of the requirements; the cost, availability and effectiveness of emissions control technology; the price, distribution method and availability of offsets and allowances used for compliance; government-imposed compliance costs; and the existence and nature of incremental cost recovery mechanisms. Examples of how new requirements may impact the Registrants include:

- Additional costs may be incurred to purchase required emissions allowances under any market-based cap-and-trade system in excess of allocations that are received at no cost. These purchases would be necessary until new technologies could be developed and deployed to reduce emissions or lower carbon generation is available;
- Acquiring and renewing construction and operating permits for new and existing generating facilities may be costly and difficult;
- Additional costs may be incurred to purchase and deploy new generating technologies;
- Costs may be incurred to retire existing coal-fueled generating facilities before the end of their otherwise useful lives or to convert them to burn fuels, such as natural gas or biomass, that result in lower emissions;
- Operating costs may be higher and generating unit outputs may be lower;
- Higher interest and financing costs and reduced access to capital markets may result to the extent that financial markets view climate change and GHG emissions as a greater business risk; and
- The relevant Registrant's natural gas pipeline operations and capacity sales, electric transmission and retail sales may be impacted in response to changes in customer demand and requirements to reduce GHG emissions.

The impact of events or conditions caused by climate change, whether from natural processes or human activities, are uncertain and could vary widely, from highly localized to worldwide, and the extent to which a utility's operations may be affected is uncertain. Climate change may cause physical and financial risks through, among other things, sea level rise, changes in precipitation and extreme weather events. Consumer demand for energy may increase or decrease, based on overall changes in weather and as customers promote lower energy consumption through the continued use of energy efficiency programs or other means. Availability of resources to generate electricity, such as water for hydroelectric production and cooling purposes, may also be impacted by climate change and could influence the Registrants' existing and future electricity generating portfolio. These issues may have a direct impact on the costs of electricity production and increase the price customers pay or their demand for electricity.

Implementing actions required under, and otherwise complying with, new federal and state laws and regulations and changes in existing ones are among the most challenging aspects of managing utility operations. The Registrants cannot accurately predict the type or scope of future laws and regulations that may be enacted, changes in existing ones or new interpretations by agency orders or court decisions, nor can each Registrant determine their impact on it at this time; however, any one of these could adversely affect each Registrant's financial results through higher capital expenditures and operating costs, early closure of generating facilities or lower tax benefits or restrict or otherwise cause an adverse change in how each Registrant operates its business. To the extent that each Registrant is not allowed by its regulators to recover or cannot otherwise recover the costs to comply with new laws and regulations or changes in existing ones, the costs of complying with such additional requirements could have a material adverse effect on the relevant Registrant's financial results. Additionally, even if such costs are

recoverable in rates, if they are substantial and result in rates increasing to levels that substantially reduce customer demand, this could have a material adverse effect on the relevant Registrant's financial results.

Recovery of costs and certain activities by each Registrant is subject to regulatory review and approval, and the inability to recover costs or undertake certain activities may adversely affect each Registrant's financial results.

State Regulatory Rate Review Proceedings

The Utilities establish rates for their regulated retail services through state regulatory proceedings. These proceedings typically involve multiple parties, including government bodies and officials, consumer advocacy groups and various consumers of energy, who have differing concerns but generally have the common objective of limiting rate increases or requesting rate decreases while also requiring the Utilities to ensure system reliability. Decisions are subject to judicial appeal, potentially leading to further uncertainty associated with the approval proceedings.

States set retail rates for consumers within their jurisdiction based in part upon the state regulatory commission's acceptance of an allocated share of total utility costs. When states adopt different methods to calculate interjurisdictional cost allocations, some costs may not be incorporated into rates of any state or other jurisdiction. Ratemaking is also generally done on the basis of estimates of normalized costs, so if a given year's realized costs are higher than normalized costs, rates may not be sufficient to cover those costs. In some cases, actual costs are lower than the normalized or estimated costs recovered through rates and from time-to-time may result in a state regulator requiring refunds to customers. Each state regulatory commission generally sets rates based on a test year established in accordance with that commission's policies. The test year data adopted by each state regulatory commission may create a lag between the incurrence of a cost and its recovery in rates. Each state regulatory commission also decides the allowed levels of expense, investment and capital structure that it deems are prudently incurred in providing the service and may disallow recovery in rates for any costs that it believes do not meet such standard. Additionally, each state regulatory commission establishes the allowed rate of return the Utilities will be given an opportunity to earn on their sources of capital. While rate regulation is premised on providing a fair opportunity to earn a reasonable rate of return on invested capital, the state regulatory commissions do not guarantee that each Registrant will be able to realize the allowed rate of return or recover all of its costs even if it believes such costs to be prudently incurred.

Some state regulatory commissions have authorized recovery of certain costs above the level assumed in establishing base rates through adjustment mechanisms, which may be subject to customer sharing. Any significant increase in fuel costs for electricity generation or purchased electricity costs could have a negative impact on the Utilities, despite efforts to minimize this impact through the use of hedging contracts and adjustment mechanisms or through future general regulatory rate reviews. Further, interjurisdictional cost allocation constraints could limit PacifiCorp's ability to recover such costs despite the adjustment mechanisms. Any of these consequences could adversely affect each Registrant's financial results.

FERC and Other Jurisdictions

The FERC authorizes cost-based rates associated with transmission services provided by the Utilities' transmission facilities. Under the Federal Power Act, the Utilities, or MISO as it relates to MidAmerican Energy, may voluntarily file, or may be obligated to file, for changes, including general rate changes, to their system-wide transmission service rates. General rate changes implemented may be subject to refund. The FERC also has responsibility for approving both cost- and market-based rates under which the Utilities sell electricity in the wholesale market, has jurisdiction over most of PacifiCorp's hydroelectric generating facilities and has broad jurisdiction over energy markets. The FERC may impose price limitations, bidding rules and other mechanisms to address some of the volatility of these markets or could revoke or restrict the ability of the Utilities to sell electricity at market-based rates, which could adversely affect each Registrant's financial results. The FERC also maintains rules concerning standards of conduct, affiliate restrictions, interlocking directorates and cross-subsidization. As a transmission owning member of MISO, MidAmerican Energy is also subject to MISO-directed modifications of market rules, which are subject to FERC approval and operational procedures. As participants in EIM, PacifiCorp, Nevada Power and Sierra Pacific are also subject to applicable California ISO rules, which are subject to FERC approval and operational procedures. The FERC may also impose substantial civil penalties for any non-compliance with the Federal Power Act and the FERC's rules and orders.

The NERC has standards in place to ensure the reliability of the electric generation system and transmission grid. The Utilities are subject to the NERC's regulations and periodic audits to ensure compliance with those regulations. The NERC may carry out enforcement actions for non-compliance and administer significant financial penalties, subject to the FERC's review.

The FERC has jurisdiction over, among other things, the construction, abandonment, modification and operation of natural gas pipelines and related facilities used in the transportation, storage and sale of natural gas in interstate commerce, including all

rates, charges and terms and conditions of service. The FERC also has market transparency authority and has adopted additional reporting and internet posting requirements for natural gas pipelines and buyers and sellers of natural gas.

Rates for the interstate natural gas transmission and storage operations at the Pipeline Companies, which include reservation, commodity, surcharges, fuel and gas lost and unaccounted for charges, are authorized by the FERC. In accordance with the FERC's ratemaking principles, the Pipeline Companies' current maximum tariff rates are designed to recover prudently incurred costs included in their pipeline systems' regulatory cost of service that are associated with the construction, operation and maintenance of their pipeline systems and to afford the Pipeline Companies an opportunity to earn a reasonable rate of return. Nevertheless, the rates the FERC authorizes the Pipeline Companies to charge their customers may not be sufficient to recover the costs incurred to provide services in any given period. Moreover, from time to time, the FERC may change, alter or refine its policies or methodologies for establishing pipeline rates and terms and conditions of service. In addition, the FERC has the authority under Section 5 of the Natural Gas Act of 1938 ("NGA") to investigate whether a pipeline may be earning more than its allowed rate of return and, when appropriate, to institute proceedings against such pipeline to prospectively reduce rates. Any such proceedings, if instituted, could result in significantly adverse rate decreases.

Under FERC policy, interstate pipelines and their customers may execute contracts at negotiated rates, which may be above or below the maximum tariff rate for that service or the pipeline may agree to provide a discounted rate, which would be a rate between the maximum and minimum tariff rates. In a rate proceeding, rates in these contracts are generally not subject to adjustment. It is possible that the cost to perform services under negotiated or discounted rate contracts will exceed the cost used in the determination of the negotiated or discounted rates, which could result either in losses or lower rates of return for providing such services. Under certain circumstances, FERC policy allows interstate natural gas pipelines to design new maximum tariff rates to recover such costs in regulatory rate reviews. However, with respect to discounts granted to affiliates, the interstate natural gas pipeline must demonstrate that the discounted rate was necessary in order to meet competition.

The Northern Powergrid Distribution Companies, as DNOs and holders of electricity distribution licenses, are subject to regulation by GEMA. Most of the revenue of a DNO is controlled by a distribution price control formula set out in the electricity distribution license. The price control formula does not directly constrain profits from year-to-year but is a control on revenue that operates independent of a significant portion of the DNO's actual costs. A resetting of the formula does not require the consent of the DNO, but if a licensee disagrees with a change to its license, it can appeal the matter to the United Kingdom's CMA. GEMA is able to impose financial penalties on DNOs that contravene any of their electricity distribution license duties or certain of their duties under British law or fail to achieve satisfactory performance of individual standards prescribed by GEMA. Any penalty imposed must be reasonable and may not exceed 10% of the DNO's revenue. During the term of any price control, additional costs have a direct impact on the financial results of the Northern Powergrid Distribution Companies.

The AUC is an independent, quasi-judicial agency established by the province of Alberta, Canada, which is responsible for, among other things, approving the tariffs of transmission facility owners, including AltaLink, and distribution utilities, acquisitions of such transmission facility owners or utilities, and construction and operation of new transmission projects in Alberta. The AUC also investigates and rules on regulated rate disputes and system access problems.

The AUC regulates and oversees Alberta's electricity transmission sector with broad authority that may impact many of AltaLink's activities, including its tariffs, rates, construction, operations and financing. In addition, AUC approval is required in connection with new energy and regulated utility initiatives in Alberta, amendments to existing approvals and financing proposals by designated utilities.

Each Registrant is involved in a variety of legal proceedings, the outcomes of which are uncertain and could adversely affect its financial results.

Each Registrant is, and in the future may become, a party to a variety of legal proceedings. Litigation is subject to many uncertainties, and the Registrants cannot predict the outcome of individual matters with certainty. It is possible that the final resolution of some of the matters in which each Registrant is involved could result in additional material payments substantially in excess of established liabilities or in terms that could require each Registrant to change business practices and procedures or divest ownership of assets. Further, litigation could result in the imposition of operational or financial penalties or injunctions and adverse regulatory consequences, any of which could limit each Registrant's ability to take certain desired actions or the denial of needed permits, licenses or regulatory authority to conduct its business, including the siting, operation or permitting of facilities. Unfavorable judgments could also require posting of surety bonds as security until the amounts awarded to plaintiffs are paid or the judgment is overturned in the appeals process. To the extent the Registrant or affected subsidiary is unable to post such a bond, other forms of security may be required such as cash or letters of credit that could reduce borrowing capacity under credit facility agreements. Any of these outcomes could have a material adverse effect on such Registrant's or BHE's

financial results. Refer to "PacifiCorp Wildfire Litigation and Insurance Risks" above for additional information regarding PacifiCorp's wildfire litigation risks.

Operational and Development Risks

The Registrants are subject to operating uncertainties and events beyond each respective Registrant's control that impact the costs to operate, maintain, repair and replace utility and interstate natural gas pipeline systems and the ability to self-insure many risks, which could adversely affect each respective Registrant's financial results.

The operation of complex utility systems or interstate natural gas pipeline and storage systems that are spread over large geographic areas involves many operating uncertainties and events beyond each respective Registrant's control. These potential events include the breakdown or failure of the Registrants' thermal, nuclear, hydroelectric, solar, wind and other electricity generating facilities and related equipment, compressors, pipelines, transmission and distribution lines and associated electric operations equipment or other equipment or processes, which could lead to catastrophic events; unscheduled outages; coal supply challenges occurring as a result of the transition away from coal-fueled resources; strikes, lockouts, other labor-related actions or shortages of qualified labor, including with respect to the Registrants' suppliers and vendors; transmission and distribution system constraints; failure to obtain, renew or maintain rights-of-way, easements and leases on U.S. federal, Native American, First Nations or tribal lands; terrorist activities or military or other actions, including physical or cyber attacks; fuel shortages or interruptions; unavailability of critical equipment, materials and supplies; low water flows and other weather-related impacts; performance below expected levels of output, capacity or efficiency; operator error; third-party excavation errors; unexpected degradation of transmission lines, pipeline systems or storage reservoirs; design, construction or manufacturing defects; and catastrophic events such as severe storms, floods, fires, extreme temperature events, wind events, earthquakes, explosions, landslides, an electromagnetic pulse, mining incidents, costly litigation, wars, terrorism, pandemics and embargoes. A catastrophic event might result in injury or loss of life, extensive property damage, environmental or natural resource damages or excessive economic loss. For example, in the event of an uncontrolled release of water at one of PacifiCorp's high hazard potential hydroelectric dams, it is probable that loss of human life, disruption of lifeline facilities and property damage could occur in the downstream population and civil or other penalties could be imposed by the FERC. The extent of that liability would be determined by the applicable state law where any such damage occurred. Any of these events or other operational events could significantly reduce or eliminate the relevant Registrant's revenue or significantly increase its expenses, thereby reducing the availability of distributions to BHE. For example, if the relevant Registrant cannot operate its electricity or natural gas facilities at full capacity due to damage caused by a catastrophic event or due to supply constraints, its revenue could decrease and its expenses could increase due to the need to obtain energy from more expensive sources.

The Registrants self-insure many risks, and current and future insurance coverage may not be sufficient to replace lost revenue or cover repair and replacement costs or other damages. Further, third-party liability insurance coverage may be costly or unavailable as a result of increasing risks associated with catastrophic wildfires as discussed below. The scope, cost and availability of each Registrant's insurance coverage may change, including the portion that is self-insured.

Any reduction of each Registrant's revenue or increase in its expenses resulting from the risks described above, could adversely affect the relevant Registrant's financial results. Refer also to "PacifiCorp Wildfire Litigation and Insurance Risks" above for additional information regarding PacifiCorp's wildfire insurance risks.

The Registrants are subject to increasing risks from catastrophic wildfires and may be unable to obtain enough third-party liability insurance coverage at a reasonable cost or at all and insurance coverage on existing wildfire claims could be insufficient to cover all losses, all of which could materially affect the Registrants financial results and liquidity.

The risk of catastrophic and severe wildfires has increased in the western U.S. giving rise to the potential for large damage claims against utilities for fire-related losses. Catastrophic and severe wildfires can occur in PacifiCorp, Nevada Power and Sierra Pacific's ("Western Domestic Utilities") service territories even when the Western Domestic Utilities effectively implement their wildfire mitigation plans and prudently manage their systems.

In California, for example, where PacifiCorp operates, "inverse condemnation" currently exposes utilities to potential liability for property damages where the utility's electrical equipment was a substantial cause of the wildfire. California courts have held that utilities can be held liable under inverse condemnation without being found negligent and regardless of fault. California law also permits inverse condemnation plaintiffs to recover attorney's fees. As a result of inverse condemnation being applied to utilities and wildfire damages, recent losses recorded by insurance companies, and the risk of an increase in the frequency, duration and size of wildfires, insurance for wildfire liabilities may not be available or may be available only at rates that are prohibitively expensive. In addition, even if insurance for wildfire liabilities is available, it may not be available in amounts

necessary to cover potential losses. Uninsured losses and increases in the cost of insurance may be challenged when PacifiCorp seeks cost recovery and may not be recoverable in customer rates.

The Western Domestic Utilities monitor weather conditions with specific thresholds for designated high fire consequence areas to help ensure the safe and reliable operation of their systems during periods of elevated wildfire ignition risk. Should weather conditions become extreme, the Western Domestic Utilities may de-energize certain sections of their transmission and distribution facilities as a last resort to minimize risk to the public. These "public safety power shutoffs" could be subject to increased scrutiny by regulators and policy makers. And, although "public safety power shutoffs" are intended to minimize risk of wildfire ignition, de-energization may cause other damages for which the Western Domestic Utilities could be held liable.

Refer also to "PacifiCorp Wildfire Litigation and Insurance Risks" above for additional information regarding PacifiCorp's wildfire insurance risks.

Each Registrant is actively pursuing, developing and constructing new or expanded facilities, the completion and expected costs of which are subject to significant risk, and each Registrant has significant funding needs related to its planned capital expenditures.

Each Registrant actively pursues, develops and constructs new or expanded facilities. Each Registrant expects to incur significant annual capital expenditures over the next several years. Such expenditures may include construction and other costs for new electricity generating facilities, electric transmission or distribution projects, environmental control and compliance systems, natural gas storage facilities, new or expanded pipeline and local distribution systems, and continued maintenance and upgrades of existing assets.

Development and construction of major facilities are subject to substantial risks, including fluctuations in the price and availability of commodities, manufactured goods, equipment, and the imposition of tariffs thereon when sourced by foreign providers, labor, siting and permitting and changes in environmental and operational compliance matters, load forecasts and other items over a multi-year construction period, as well as counterparty risk and the economic viability of the Registrants' suppliers, customers and contractors. Certain of the Registrants' construction projects are substantially dependent upon a single supplier or contractor and replacement of such supplier or contractor may be difficult and cannot be assured. These risks may result in the inability to timely complete a project or higher than expected costs to complete an asset and place it in-service and, in extreme cases, the loss of the power purchase agreements or other long-term off-take contracts underlying such projects. Such costs may not be recoverable in the regulated rates or market or contract prices each Registrant is able to charge its customers. Delays in construction of renewable projects may result in delayed in-service dates which may result in the loss of anticipated revenue or income tax benefits. It is also possible that additional generation needs may be obtained through power purchase agreements, which could increase long-term purchase obligations and force reliance on the operating performance of a third party. The inability to successfully and timely complete a project, avoid unexpected costs or recover any such costs could adversely affect such Registrant's financial results.

Furthermore, each Registrant depends upon both internal and external sources of liquidity to provide working capital and to fund capital requirements. If BHE does not provide needed funding to its subsidiaries and the subsidiaries are unable to obtain funding from external sources, they may need to postpone or cancel planned capital expenditures. Refer to "PacifiCorp Wildfire Litigation and Insurance Risks" above for additional information regarding the impact of wildfire litigation risks on PacifiCorp's capital expenditures.

A significant sustained decrease in demand for electricity or natural gas in the markets served by each Registrant would decrease its operating revenue, could impact its planned capital expenditures and could adversely affect its financial results.

A significant sustained decrease in demand for electricity or natural gas in the markets served by each Registrant would decrease its operating revenue, could impact its planned capital expenditures and could adversely affect its financial results. Factors that could lead to a decrease in market demand include, among others:

- a depression, recession or other adverse economic condition that results in a lower level of economic activity or reduced spending by consumers on electricity or natural gas;
- an increase in the market price of electricity or natural gas or a decrease in the price of other competing forms of energy;
- shifts in competitively priced natural gas supply sources away from the sources connected to the Pipeline Companies' systems, including shale gas sources;

- efforts by customers, legislators and regulators to reduce the consumption of electricity generated or distributed by each Registrant through various existing laws and regulations, as well as, deregulation, conservation, energy efficiency and private generation measures and programs;
- laws or policy pronouncements mandating or encouraging renewable energy sources, which may decrease the demand for electricity and natural gas or change the market prices of these commodities;
- higher fuel taxes or other governmental or regulatory actions that increase, directly or indirectly, the cost of natural gas or other fuel sources for electricity generation or that limit the use of natural gas or the generation of electricity from fossil fuels;
- a shift to more energy-efficient or alternative fuel machinery or an improvement in fuel economy, whether as a result of technological advances by manufacturers, legislation mandating higher fuel economy or lower emissions, price differentials, incentives or otherwise;
- a reduction in the state or federal subsidies or tax incentives that are provided to agricultural, industrial or other customers, or a significant sustained change in prices for commodities such as ethanol or corn for ethanol manufacturers; and
- sustained mild weather that reduces heating or cooling needs.

Each Registrant's operating results may fluctuate on a seasonal and quarterly basis and may be adversely affected by weather.

In most parts of the U.S. and other markets in which each Registrant operates, demand for electricity peaks during the summer months when irrigation and cooling needs are higher. Market prices for electricity also generally peak at that time. In other areas, including the western portion of PacifiCorp's service territory, demand for electricity peaks during the winter when heating needs are higher. In addition, demand for natural gas and other fuels generally peaks during the winter. This is especially true in MidAmerican Energy's and Sierra Pacific's retail natural gas businesses. Further, extreme weather conditions, such as heat waves, winter storms or floods could cause these seasonal fluctuations to be more pronounced. Periods of low rainfall or snowpack may negatively impact electricity generation at PacifiCorp's hydroelectric generating facilities, which may result in greater purchases of electricity from the wholesale market or from other sources at market prices. Additionally, PacifiCorp and MidAmerican Energy have added substantial wind-powered generating capacity, and BHE's unregulated subsidiaries are adding solar-powered and wind-powered generating capacity, each of which is also a climate-dependent resource.

As a result, the overall financial results of each Registrant may fluctuate substantially on a seasonal and quarterly basis. Each Registrant has historically provided less service, and consequently earned less income, when weather conditions are mild. Unusually mild weather in the future may adversely affect each Registrant's financial results through lower revenue or margins. Conversely, unusually extreme weather conditions could increase each Registrant's costs to provide services and could adversely affect its financial results. The extent of fluctuation in each Registrant's financial results may change depending on a number of factors related to its regulatory environment and contractual agreements, including its ability to recover energy costs, the existence of revenue sharing provisions as it relates to MidAmerican Energy, Nevada Power and Sierra Pacific, and terms of its wholesale sale contracts.

Each Registrant is subject to market risk associated with the wholesale energy markets, which could adversely affect its financial results.

In general, each Registrant's primary market risk is adverse fluctuations in the market price of wholesale electricity and fuel, including natural gas, coal and fuel oil, which is compounded by volumetric changes affecting the availability of or demand for electricity and fuel. The market price of wholesale electricity may be influenced by several factors, such as the adequacy or type of generating capacity, scheduled and unscheduled outages of generating facilities, prices and availability of fuel sources for generation, disruptions or constraints to transmission and distribution facilities, weather conditions, demand for electricity, economic growth and changes in technology. Volumetric changes are caused by fluctuations in generation or changes in customer needs that can be due to the weather, electricity and fuel prices, the economy, regulations and governmental policies or customer behavior. For example, the Utilities purchase electricity and fuel in the open market as part of their normal operating businesses. If market prices rise, especially in a time when larger than expected volumes must be purchased at market prices, the Utilities may incur significantly greater expenses than anticipated. Likewise, if electricity market prices decline in a period when the Utilities are a net seller of electricity in the wholesale market, the Utilities could earn less revenue. Although the Utilities have ECAMs, the risks associated with changes in market prices may not be fully mitigated due to customer

sharing bands as it relates to PacifiCorp and other factors, including potential interjurisdictional allocation constraints and extended recovery periods that negatively impact cash flows.

Certain of BHE's subsidiaries are subject to the risk that customers will not renew their contracts or that BHE's subsidiaries will be unable to obtain new customers for expanded capacity, each of which could adversely affect its financial results.

If BHE's subsidiaries are unable to renew, remarket, or find replacements for their customer agreements on favorable terms, BHE's subsidiaries' sales volumes and operating revenue would be exposed to reduction and increased volatility. For example, without the benefit of long-term transportation agreements, BHE cannot assure that the Pipeline Companies will be able to transport natural gas at efficient capacity levels. Substantially all of the Pipeline Companies' revenue is generated under transportation, storage and LNG contracts that periodically must be renegotiated and extended or replaced, and the Pipeline Companies are dependent upon relatively few customers for a substantial portion of their revenue. Similarly, without long-term power purchase agreements, BHE cannot assure that its unregulated power generators will be able to operate profitably. Failure to maintain existing long-term agreements or secure new long-term agreements, or being required to discount rates significantly upon renewal or replacement, could adversely affect BHE's consolidated financial results. The replacement of any existing long-term agreements depends on market conditions and other factors that may be beyond BHE's subsidiaries' control.

Each Registrant is subject to counterparty risk, which could adversely affect its financial results.

Each Registrant is subject to counterparty credit risk related to contractual payment obligations with wholesale suppliers and customers. Adverse economic conditions or other events affecting counterparties with whom each Registrant conducts business could impair the ability of these counterparties to meet their payment obligations. Each Registrant depends on these counterparties to remit payments on a timely basis. Each Registrant monitors the creditworthiness of its wholesale suppliers and customers in an attempt to reduce the impact of any potential counterparty default. If strategies used to minimize these risk exposures are ineffective or if a Registrant's wholesale suppliers' or customers' financial condition deteriorates or they otherwise become unable to pay, it could have a significant adverse impact on the Registrant's liquidity and its financial results.

Each Registrant is subject to counterparty performance risk related to performance of contractual obligations by wholesale suppliers, customers and contractors. Each Registrant relies on wholesale suppliers to deliver commodities, primarily natural gas, coal and electricity, in accordance with short- and long-term contracts. Failure or delay by suppliers to provide these commodities pursuant to existing contracts could disrupt the delivery of electricity and require the Utilities to incur additional expenses to meet customer needs. In addition, when these contracts terminate, the Utilities may be unable to purchase the commodities on terms equivalent to the terms of current contracts.

Each Registrant relies on wholesale customers to take delivery of the energy they have committed to purchase. Failure of customers to take delivery may require the relevant Registrant to find other customers to take the energy at lower prices than the original customers committed to pay. If each Registrant's wholesale customers are unable to fulfill their obligations, there may be a significant adverse impact on its financial results.

The Northern Powergrid Distribution Companies' customers are concentrated in a small number of electricity supply businesses. AltaLink's primary source of operating revenue is the AESO. Generally, a single customer purchases the energy from BHE's independent power projects in the U.S. pursuant to long-term power purchase agreements. Any material payment or other performance failure by the counterparties in these arrangements could have a significant adverse impact on BHE's consolidated financial results.

Inflation and changes in commodity prices and transportation fuel costs may adversely affect each Registrant's financial results.

Inflation and increases in commodity prices and transportation fuel costs may affect each Registrant by increasing both operating and capital costs. As a result of existing rate agreements, contractual arrangements or competitive price pressures, each Registrant may not be able to pass the inflated costs on to its customers. If a Registrant is unable to manage cost increases or pass them on to its customers, its financial results could be adversely affected.

Physical or cyber attacks, both threatened and actual, could impact each Registrant's operations and could adversely affect its financial results.

Each Registrant relies on technology in virtually all aspects of its business. Like any business, the Registrants' technology systems are a target for computer viruses, malicious codes, unauthorized access, phishing efforts, denial-of-service attacks and other cyber attacks and each Registrant expects to be subject to attempted attacks in the future and will continue to adapt defensive capabilities as such attacks become more sophisticated and frequent. A significant disruption or failure of its technology systems by cyber or physical attack could result in service interruptions, safety failures, security events, regulatory compliance failures, an inability to protect information and assets against unauthorized users, and other operational difficulties. Attacks perpetrated against each Registrant's systems could result in loss of assets and critical information and expose it to remediation costs and reputational damage.

Although the Registrants have taken steps intended to mitigate these risks, a significant disruption or cyber intrusion at one or more of each Registrant's operations could adversely affect the impacted Registrant's financial results. Cyber attacks could further adversely affect each Registrant's ability to operate facilities, information technology and business systems, or compromise sensitive customer and employee information. In addition, physical or cyber attacks against key suppliers or service providers could have a similar effect on each Registrant. Additionally, if each Registrant is unable to acquire, develop, implement, adopt or protect rights around new technology, it may suffer a competitive disadvantage.

Much of BHE's growth has been achieved through acquisitions, and any such acquisition may not be successful.

Much of BHE's growth has been achieved through acquisitions. Future acquisitions may range from buying individual assets to the purchase of entire businesses. BHE will continue to investigate and pursue opportunities for future acquisitions that it believes, but cannot assure, may increase value and expand or complement existing businesses. BHE may participate in bidding or other negotiations at any time for such acquisition opportunities which may or may not be successful. An acquisition could cause an interruption of, or a loss of momentum in, the activities of one or more of BHE's subsidiaries. In addition, the final orders of regulatory authorities approving acquisitions may be subject to appeal by third parties. The diversion of BHE management's attention and any delays or difficulties encountered in connection with the approval and integration of the acquired operations could adversely affect BHE's combined businesses and financial results and could impair its ability to realize the anticipated benefits of the acquisition. BHE cannot assure that future acquisitions, if any, or any integration efforts will be successful, or that BHE's ability to repay its obligations will not be adversely affected by any future acquisitions.

Certain Registrants are subject to the unique risks associated with nuclear generation.

The ownership and operation of nuclear generating facilities, such as MidAmerican Energy's 25% interest in Quad Cities Station, involves certain risks. These risks include, among other items, mechanical or structural problems, inadequacy or lapses in maintenance protocols, the impairment of reactor operation and safety systems due to human error, the costs of storage, handling and disposal of nuclear materials, compliance with and changes in regulation of nuclear generating facilities, limitations on the amounts and types of insurance coverage commercially available, economic risks impacting the current and expected value of the facilities, and uncertainties with respect to the technological and financial aspects of decommissioning nuclear facilities at the end of their useful lives. Additionally, Constellation Energy, the 75% owner and operator of the facility, may respond to the occurrence of any of these or other operational or economic risks in a manner that negatively impacts MidAmerican Energy, including closure of Quad Cities Station prior to the expiration of its operating license. The prolonged unavailability, or early closure, of Quad Cities Station due to operational or economic factors could have a materially adverse effect on the relevant Registrant's financial results, particularly when the cost to produce power at the generating facility is significantly less than market wholesale prices. The following are among the more significant of these risks:

- *Operational Risk* - Operations at any nuclear generating facility could degrade to the point where the generating facility would have to be shut down. If such degradations were to occur, the process of identifying and correcting the causes of the operational downgrade to return the generating facility to operation could require significant time and expenses, resulting in both lost revenue and increased fuel and purchased electricity costs to meet supply commitments. Rather than incurring substantial costs to restart the generating facility, the generating facility could be shut down. Furthermore, a shut-down or failure at any other nuclear generating facility could cause regulators to require a shut-down or reduced availability at Quad Cities Station.

In addition, issues relating to the disposal of nuclear waste material, including the availability, unavailability and expenses of a permanent repository for spent nuclear fuel could adversely impact operations as well as the cost and ability to decommission nuclear generating facilities, including Quad Cities Station, in the future.

- *Regulatory Risk* - The NRC may modify, suspend or revoke licenses and impose civil penalties for failure to comply with applicable Atomic Energy Act regulations or the terms of the licenses of nuclear facilities. Unless extended, the NRC operating licenses for Quad Cities Station will expire in 2032. Changes in regulations by the NRC could require a substantial increase in capital expenditures or result in increased operating or decommissioning costs.
- *Nuclear Accident and Catastrophic Risks* - Accidents and other unforeseen catastrophic events have occurred at nuclear facilities other than Quad Cities Station, both in the U.S. and elsewhere, such as at the Fukushima Daiichi nuclear generating facility in Japan as a result of the earthquake and tsunami in March 2011. The consequences of an accident or catastrophic event can be severe and include loss of life and property damage. Any resulting liability from a nuclear accident or catastrophic event could exceed the relevant Registrant's resources, including insurance coverage.
- *Economic Risks* - Market power prices, results of capacity auctions, potential legislative and regulatory actions that impact the compensation received from state or federal policies, reliability or fuel security, and the financial impact of potential rules from the EPA requiring reduction of carbon and other emissions and the efforts of states to implement those final rules may affect the current and expected economic value of the nuclear generating facility resulting in an early nuclear generating facility retirement.

Potential terrorist activities and the impact of military or other actions, including sanctions, export controls and similar measures, could adversely affect each Registrant's financial results.

The ongoing threat of terrorism and the impact of military or other actions by nations or politically, ethnically or religiously motivated organizations regionally or globally may create increased political, economic, social and financial market instability, which could subject each Registrant's operations to increased risks. Additionally, the U.S. government has issued warnings that energy assets, specifically pipeline, nuclear generation, transmission and other electric utility infrastructure, are potential targets for terrorist attacks. Further, the potential or actual outbreak of war or other hostilities and the resulting economic sanctions on aggressor nations, as well as the existing and potential further responses from such aggressors or other countries to such sanctions and military actions, could adversely affect global and regional economies and financial markets. For instance, a ban on imports of oil, liquefied natural gas and coal to the U.S. could contribute to increases in prices for such commodities in the U.S. and elsewhere which could adversely affect each Registrant's business. Further, each Registrant's business must be conducted in compliance with applicable economic and trade sanctions laws and regulations, including those administered and enforced by the U.S. Department of Treasury's Office of Foreign Assets Control, the U.S. Department of State, the U.S. Department of Commerce, the United Nations Security Council and other relevant governmental authorities in the U.S., Canada, the United Kingdom and European Union, which include sanctions that could potentially restrict or prohibit each Registrant's relationships with certain suppliers and customers. Political, economic, social or financial market instability or damage to or interference with the operating assets of the Registrants, customers or suppliers, or continued increases in the price of natural gas and other petroleum commodities may result in business interruptions, lost revenue, higher costs, disruption in fuel supplies, lower energy consumption and unstable markets, particularly with respect to electricity and natural gas, and increased security, repair or other costs, any of which may materially adversely affect each Registrant in ways that cannot be predicted at this time. Any of these risks could materially affect BHE's consolidated financial results. Furthermore, instability in the financial markets as a result of terrorism or war could also materially adversely affect each Registrant's ability to raise capital.

Each Registrant's business could be adversely affected by epidemics, pandemics or other outbreaks.

Each Registrant's business could be adversely affected by epidemics, pandemics or other outbreaks generally and more specifically in the markets in which we operate, including, without limitation, if each Registrant's utility customers experience decreases in demand for their products and services or otherwise reduce their consumption of electricity or natural gas that the respective Registrant supplies, or if such Registrant experiences material payment defaults by its customers. In addition, each Registrant's results and financial condition may be adversely affected by federal, state or local and foreign legislation related to such epidemics, pandemics or other outbreaks (or other similar laws, regulations, policies, orders or other governmental or regulatory actions) that would impose a moratorium on terminating electric or natural gas utility services, including related assessment of late fees, due to non-payment or other circumstances. Additionally, HomeServices' real estate businesses could experience a decline (which could be significant) in real estate transactions if potential customers elect to defer purchases in reaction to any epidemic, pandemic or other outbreak or due to general economic uncertainty such as high unemployment levels, in some or all of the real estate markets in which HomeServices operates. The government and regulators could impose other requirements on each Registrant's business that could have an adverse impact on such Registrant's financial results.

Further, epidemics, pandemics or other outbreaks could disrupt supply chains (including supply chains for energy generation, steel or transmission wire) relating to the markets each Registrant serves, which could adversely impact such Registrant's ability to generate or supply power. In addition, such disruptions to the supply chain could delay certain construction and other capital expenditure projects, including construction and repowering of the Registrants' renewable generation projects. Such disruptions could adversely affect the impacted Registrant's future financial results.

Such declines in demand, any inability to generate or supply power or delays in capital projects could also significantly reduce cash flows at BHE's subsidiaries, thereby reducing the availability of distributions to BHE, which could adversely affect its financial results.

Cyclical fluctuations and competition in the residential real estate brokerage and mortgage businesses could adversely affect HomeServices.

The residential real estate brokerage and mortgage industries tend to experience cycles of greater and lesser activity and profitability and are typically affected by changes in economic conditions, which are beyond HomeServices' control. Any of the following, among others, are examples of items that could have a material adverse effect on HomeServices' businesses by causing a general decline in the number of home sales, sale prices or the number of home financings which, in turn, would adversely affect its financial results:

- rising interest rates or unemployment rates, including a sustained high unemployment rate in the U.S.;
- periods of economic slowdown or recession in the markets served or the adverse effects on market actions as a result of epidemics, pandemics or other outbreaks;
- decreasing home affordability;
- lack of available mortgage credit for potential homebuyers, such as the reduced availability of credit, which may continue into future periods;
- inadequate home inventory levels;
- sources of new competition; and
- changes in applicable tax law.

BHE holds investments in foreign countries that are exposed to risks related to fluctuations in foreign currency exchange rates and increased economic, regulatory and political risks.

BHE's business operations and investments outside the U.S. increase its risk related to fluctuations in foreign currency exchange rates, primarily the British pound and the Canadian dollar. BHE's principal reporting currency is the U.S. dollar, and the value of the assets and liabilities, earnings, cash flows and potential distributions from its foreign operations changes with the fluctuations of the currency in which they transact. BHE may selectively reduce some foreign currency exchange rate risk by, among other things, requiring contracted amounts be settled in, or indexed to, U.S. dollars or a currency freely convertible into U.S. dollars, or hedging through foreign currency derivatives. These efforts, however, may not be effective and could negatively affect BHE's consolidated financial results.

In addition to any disruption in the global financial markets, the economic, regulatory and political conditions in some of the countries where BHE has operations or is pursuing investment opportunities may present increased risks related to, among others, inflation, foreign currency exchange rate fluctuations, currency repatriation restrictions, nationalization, renegotiation, privatization, availability of financing on suitable terms, customer creditworthiness, construction delays, business interruption, political instability, civil unrest, guerilla activity, terrorism, pandemics, expropriation, trade sanctions, contract nullification and changes in law, regulations or tax policy. BHE may not choose to or be capable of either fully insuring against or effectively hedging these risks.

Item 1B. Unresolved Staff Comments

Not applicable.

Item 1C. Cybersecurity

CYBER RISK MANAGEMENT AND STRATEGY

BHE and its Subsidiary Registrants recognize that maintaining processes for identifying, assessing and managing cybersecurity threats is important in dealing with their significant business risks. As such, BHE has implemented a framework for cybersecurity and cyber-related information management across its businesses. BHE's Chief Security Office ("CSO") drives collective focus and central coordination of BHE's cyber and physical security programs. The CSO identifies the strategic framework that promotes standardization of business security policies and practices and provides direction in managing security risks. Although the CSO provides oversight, the businesses retain accountability for executing company security objectives, policies and practices within their areas of responsibility.

BHE manages cybersecurity threats through its proactive risk management program and cybersecurity awareness program. BHE's businesses are certified against the ISO 27001 standard. The standard is authored by the International Organization for Standardization ("ISO") of Geneva, Switzerland. To achieve the certification, each business must sustain an information security management system that includes a risk-based framework to identify and manage information security risks through a continuous improvement cycle. The risks and controls identified in the system must be approved by top management and confirmed through annual internal and external ISO audits prior to certification.

In addition, BHE's compliance requirements include the North American Electric Reliability Corporation Critical Infrastructure Protection Standards, the Transportation Security Administration Pipeline Security Directives and the United Kingdom Center for the Protection of National Infrastructure Standards as applicable to each of the companies. These requirements are audited and assessed as mandated by applicable government agencies.

Each Registrant relies on technology in virtually all aspects of its business. Like any business, the Registrants' technology systems are a target for cyber attacks. Each Registrant expects to be subject to attempted attacks in the future and will continue to adapt defensive capabilities as such attacks become more sophisticated and frequent. A significant disruption or failure of its technology systems by cyber or physical attack could result in service interruptions, safety failures, security events, regulatory compliance failures, an inability to protect information and assets against unauthorized users, and other operational difficulties. Attacks perpetrated against each Registrant's systems could result in loss of assets and critical information and expose it to remediation costs and reputational damage.

In certain circumstances, BHE relies on third-party service providers for a variety of products and services to run its information systems. This dependence exposes BHE, along with others who use these service providers, to the impact of a cyber attack on these providers. Cyber attacks at a third-party service provider could have a significant financial, operational, or reputational impact. BHE continuously monitors the risks associated with its service providers.

GOVERNANCE

BHE's Board of Directors has delegated responsibility for oversight of BHE's cybersecurity risk management program to its Executive Committee, consisting of BHE's Chief Executive Officer, who is a management member of the BHE Board of Directors, and the BHE Chief Financial Officer and General Counsel, who are not management members of the BHE Board of Directors.

BHE's CSO is responsible for cyber and physical security across BHE and its Subsidiary Registrants. The CSO is responsible for identifying, assessing and managing cyber risk for BHE and its Subsidiary Registrants. The Executive Committee has evaluated the expertise of the CSO and determined that it possesses the knowledge and expertise necessary to oversee BHE's cybersecurity risk management processes.

The CSO provides, at least annually, updates to the Executive Committee on:

- Strategic cyber and physical security initiatives
- Current threat and risk landscape impacting the organization
- Security compliance with regulatory requirements
- Compliance with ISO 27001 framework
- Number and impact of incidents reported through the BHE cybersecurity incident reporting process

BHE's Cybersecurity Reporting Framework enables BHE to use a repeatable and timely process to identify, assess and manage any security incidents for materiality reporting. Each BHE business is required to report significant cybersecurity events to BHE. The Executive Committee and CSO together review incident reports to determine whether a cyber incident report should be filed with the SEC.

Item 2. Properties

Each Registrant's energy properties consist of the physical assets necessary to support its electricity and natural gas businesses. Properties of the relevant Registrant's electricity businesses include electric generation, transmission and distribution facilities, as well as coal mining assets that support certain of PacifiCorp's electric generating facilities. Properties of the relevant Registrant's natural gas businesses include natural gas distribution facilities, interstate pipelines, storage facilities, LNG facilities, compressor stations and meter stations. The transmission and distribution assets are primarily within each Registrant's service territories. In addition to these physical assets, the Registrants have rights-of-way, mineral rights and water rights that enable each Registrant to utilize its facilities. It is the opinion of each Registrant's management that the principal depreciable properties owned by it are in good operating condition and are well maintained. Pursuant to separate financing agreements, substantially all of PacifiCorp's electric utility properties, MidAmerican Energy's electric utility properties in the state of Iowa, Nevada Power's and Sierra Pacific's properties in the state of Nevada, AltaLink's transmission properties and substantially all of the assets of the subsidiaries of BHE Renewables that are direct or indirect owners of generation projects are pledged or encumbered to support or otherwise provide the security for the related subsidiary debt. For additional information regarding each Registrant's energy properties, refer to Item 1 of this Form 10-K and Notes 4, 5 and 22 of the Notes to Consolidated Financial Statements of Berkshire Hathaway Energy in Item 8 of this Form 10-K, Notes 3 and 4 of the Notes to Consolidated Financial Statements of PacifiCorp in Item 8 of this Form 10-K, Notes 3 and 4 of the Notes to Financial Statements of MidAmerican Energy in Item 8 of this Form 10-K, Notes 3 and 4 of the Notes to Consolidated Financial Statements of Nevada Power in Item 8 of this Form 10-K, Notes 3 and 4 of the Notes to Consolidated Financial Statements of Sierra Pacific in Item 8 of this Form 10-K, Notes 4 and 5 of the Notes to Consolidated Financial Statements of Eastern Energy Gas in Item 8 of this Form 10-K and Notes 3 and 4 of the Notes to Consolidated Financial Statements of EGTS in Item 8 of this Form 10-K.

The following table summarizes Berkshire Hathaway Energy's operating electric generating facilities as of December 31, 2024:

Energy Source	Entity	Location by Significance	Facility Net Capacity (MWs)	Net Owned Capacity (MWs)
Wind	PacifiCorp, MidAmerican Energy, BHE Canada, BHE Montana and BHE Renewables	Iowa, Wyoming, Texas, Montana, Nebraska, Washington, California, Illinois, Canada, Oregon and Kansas	12,659	12,659
Natural gas	PacifiCorp, MidAmerican Energy, NV Energy, BHE Canada and BHE Renewables	Nevada, Utah, Iowa, Wyoming, Illinois, Washington, Oregon, Texas, New York, Arizona and Canada	12,887	12,251
Coal	PacifiCorp, MidAmerican Energy and NV Energy	Iowa, Wyoming, Utah, Nevada, Colorado and Montana	12,146	7,466
Solar	MidAmerican Energy, NV Energy, Northern Powergrid and BHE Renewables	California, Australia, Nevada, Texas, Arizona, Iowa and Minnesota	2,270	2,122
Hydroelectric	PacifiCorp, MidAmerican Energy and BHE Renewables	Washington, Oregon, Idaho, Utah, Hawaii, Montana, Illinois, California and Wyoming	985	985
Nuclear	MidAmerican Energy	Illinois	1,811	452
Geothermal	PacifiCorp and BHE Renewables	California and Utah	377	377
Total			43,135	36,312

Additionally, as of December 31, 2024, the Company has electric generating facilities that are under construction in Wyoming, Nevada, West Virginia and California having total Facility Net Capacity and Net Owned Capacity of 1,085 MWs.

As of December 31, 2024, the Company also has battery energy storage systems in Nevada, Montana, West Virginia and Oregon having total Facility Net Capacity and Net Owned Capacity in operation of 320 MW and under construction of 527 MW.

The right to construct and operate each Registrant's electric transmission and distribution facilities and interstate natural gas pipelines across certain property was obtained in most circumstances through negotiations and, where necessary, through prescription, eminent domain or similar rights. PacifiCorp, MidAmerican Energy, Nevada Power, Sierra Pacific, BHE GT&S, Northern Natural Gas and Kern River in the U.S.; Northern Powergrid (Northeast) plc and Northern Powergrid (Yorkshire) plc in Great Britain; and AltaLink in Alberta, Canada continue to have the power of eminent domain or similar rights in each of the jurisdictions in which they operate their respective facilities, but the U.S. and Canadian utilities do not have the power of eminent domain with respect to governmental, Native American or Canadian First Nations' tribal lands. Although the main Kern River pipeline crosses the Moapa Indian Reservation, all facilities in the Moapa Indian Reservation are located within a utility corridor that is reserved to the U.S. Department of Interior, Bureau of Land Management.

With respect to real property, each of the electric transmission and distribution facilities and interstate natural gas pipelines fall into two basic categories: (1) parcels that are owned in fee, such as certain of the electric generating facilities, electric substations, natural gas compressor stations, natural gas meter stations and office sites; and (2) parcels where the interest derives from leases, easements (including prescriptive easements), rights-of-way, permits or licenses from landowners or governmental authorities permitting the use of such land for the construction, operation and maintenance of the electric transmission and distribution facilities and interstate natural gas pipelines. Each Registrant believes it has satisfactory title or interest to all of the real property making up their respective facilities in all material respects.

Item 3. Legal Proceedings

BERKSHIRE HATHAWAY ENERGY AND PACIFICORP

In September 2020, a severe weather event resulting in high winds, low humidity and warm temperatures contributed to several major wildfires, including the 2020 Wildfires, which resulted in real and personal property and natural resource damage, personal injuries and loss of life, and widespread power outages in Oregon and Northern California. The wildfires spread across certain parts of PacifiCorp's service territory and surrounding areas across multiple counties in Oregon and California, including Siskiyou County, California; Jackson County, Oregon; Douglas County, Oregon; Marion County, Oregon; Lincoln County, Oregon; and Klamath County, Oregon, burning over 500,000 acres in aggregate. Third-party reports for these wildfires indicate over 2,000 structures destroyed, including residences; several structures damaged; multiple individuals injured; and several fatalities.

In July 2022, the 2022 McKinney Fire began in the Oak Knoll Ranger District of the Klamath National Forest in Siskiyou County, California located in PacifiCorp's service territory, burning over 60,000 acres. Third-party reports indicate that the 2022 McKinney Fire resulted in 11 structures damaged; 185 structures destroyed, including residences; 12 injuries; and four fatalities.

As described below, a significant number of complaints and demands alleging similar claims have been filed in Oregon and California related to the Wildfires. Amounts sought in outstanding complaints and demands filed in Oregon and in certain demands made in California totaled approximately \$3 billion, excluding any doubling or trebling of damages included in the complaints and the mass complaints described below that seek \$48 billion. Generally, the complaints filed in California do not specify damages sought and are excluded from this amount. For class actions, amounts specified by the plaintiffs in the complaints include amounts based on estimates of the potential class size, which ultimately may be significantly greater than estimated. Additionally, damages are not limited to the amounts specified in the initially filed complaints as plaintiffs are frequently allowed to amend their complaints to add additional damages and amounts awarded in a court proceeding may be significantly greater than the damages specified. Oregon law provides for doubling of economic and property damages in the event the defendant is found to have acted with gross negligence, recklessness, willfulness or malice. Oregon law provides for trebling of the damages associated with timber, shrubs and produce in the event the defendant is determined to have willfully and intentionally trespassed.

Investigations into the causes and origins of the Wildfires are ongoing. For more information regarding certain legal proceedings affecting Berkshire Hathaway Energy, refer to Note 16 of the Notes to Consolidated Financial Statements of Berkshire Hathaway Energy in Part II, Item 8 of this Form 10-K, and PacifiCorp, refer to Note 14 of the Notes to Consolidated Financial Statements of PacifiCorp in Part II, Item 8 of this Form 10-K.

2020 Slater Fire California and Oregon Complaints and Demands

As described below, a significant number of complaints on behalf of plaintiffs associated with the Northern California and Southern Oregon Slater Fire ("Slater Fire") have been filed in Oregon and California. The complaints generally allege: (i) inverse condemnation; (ii) negligence; (iii) trespass; (iv) nuisance; and (v) violation of certain sections of the California Public Utilities Code and the California Health & Safety Code and request a jury trial and seek various damages. The damages sought generally include: (i) economic damages; (ii) noneconomic damages; (iii) doubling of economic damages; (iv) punitive damages; (v) pre- and post-judgment interest; and (vi) attorneys' fees and other costs. Certain complaints include wrongful death claims as described below.

Other than the claims of three individual plaintiffs who are exploring resolution and the U.S. government claim described below, all complaints filed to date for the Slater Fire have been settled.

Hitchcock et al. v. PacifiCorp and Consolidated California Slater Fire Cases

On December 16, 2020, a complaint against PacifiCorp was filed, captioned *Hitchcock et al. v. PacifiCorp*, Case No. 34-2020-00290833, ("*Hitchcock*") in California Superior Court, Sacramento County, California ("Sacramento County Superior Court California") by approximately 69 plaintiffs. The *Hitchcock* case makes similar allegations as those described above for the Slater Fire, includes a wrongful death claim for one of the two Slater Fire decedents and does not specify the amount of damages sought.

The following complaints also filed in Sacramento County Superior Court California have been consolidated into the *Hitchcock* case: *Hillman* complaint filed January 29, 2021, approximately 234 plaintiffs; *Franklin* complaint filed February 17, 2022, approximately 43 plaintiffs; *Ormsby* complaint filed April 18, 2022, approximately four plaintiffs; *Hodges* complaint filed August 23, 2022, approximately 26 plaintiffs; *Nixon* complaint filed August 31, 2022, approximately two plaintiffs; *Bleeg* complaint filed September 1, 2022, approximately 17 plaintiffs; *Lemon* complaint filed September 2, 2022, approximately 186 plaintiffs; *Sanchez* complaint filed September 7, 2022, approximately 10 plaintiffs; *Duval* complaint filed September 29, 2022, approximately 24 plaintiffs; *Fernandez* complaint filed August 17, 2023, approximately 51 plaintiffs; *Thomason* complaint filed September 7, 2023, approximately four plaintiffs; and *Bledsoe* complaint filed September 28, 2023, approximately three plaintiffs.

The complaints make similar allegations as those described above for the Slater Fire and do not specify the amount of damages sought.

In 2023, PacifiCorp settled certain claims in the consolidated *Hitchcock* case for \$8 million representing three individual plaintiffs and one commercial timber plaintiff. In the three-month period ended March 31, 2024, PacifiCorp reached additional settlements totaling \$60 million representing 165 plaintiffs, including settlement of the wrongful death claim and the *Terran* case described below. In April 2024, PacifiCorp reached additional settlements totaling \$2 million representing 16 plaintiffs, including certain plaintiffs in the *Franklin* and *Bleeg* cases. In June 2024, PacifiCorp reached a settlement totaling \$10 million for 54 plaintiffs in the California Slater Fire cases, as well as the Oregon Slater Fire cases described below. In June 2024, PacifiCorp reached additional settlements totaling \$150 million representing 378 plaintiffs and resolving substantially all individual claims in the California Slater Fire cases. As a result of the settlements, the bellwether trial scheduled for October 7, 2024, was vacated.

Other Slater Fire Cases

On August 10, 2022, a complaint against PacifiCorp was filed, captioned *Siskiyou County v. PacifiCorp*, Case No. 34-2022-00324977, by one plaintiff in Sacramento County Superior Court California. The complaint makes similar allegations as those described above for the Slater Fire and does not specify the amount of damages sought. In April 2023, PacifiCorp received a mediation demand from Siskiyou County for approximately \$6 million in damages. On May 15, 2024, the case settled for \$2 million.

On July 12, 2023, a complaint against PacifiCorp was filed, captioned *Susan Irene Terran et al. v. PacifiCorp*, Case No. 23CV27759 ("*Terran*") in Oregon Circuit Court in Multnomah County, Oregon ("Multnomah County Circuit Court Oregon"), by approximately six plaintiffs. The complaint makes similar allegations as those described above for the Slater Fire and seeks various damages, including economic damages of approximately \$10 million based on \$1 million for each of the five individual plaintiffs and \$5 million for the one non-individual plaintiff. The complaint seeks noneconomic damages to be determined at trial. The *Terran* case settled.

On September 8, 2023, a subrogation complaint against PacifiCorp was filed, captioned *Travelers Commercial Insurance Company et al. v. PacifiCorp*, Case No. 23CV008226, in Sacramento County Superior Court California by four plaintiffs. The complaint makes similar allegations as those described above for the Slater Fire and does not specify the amount of damages sought. This case settled on February 12, 2024.

Black et al. v. PacifiCorp and Consolidated Oregon Slater Fire Cases

On March 10, 2022, a complaint against PacifiCorp was filed, captioned *Susan Black et al. v. PacifiCorp*, Case No. 22CV08622, ("*Black*") in Multnomah County Circuit Court Oregon by approximately 28 plaintiffs. The complaint makes similar allegations as those described above for the Slater Fire and seeks various damages, including economic damages of approximately \$44 million based on \$1 million for each of the 24 individual plaintiffs and \$5 million for each of the four non-individual plaintiffs. The individual plaintiffs also seek unspecified noneconomic damages.

The following complaints filed in Multnomah County Circuit Court Oregon have been consolidated into the *Black* case: *Denny* complaint filed August 31, 2022, approximately seven plaintiffs and *Sparks* amended complaint filed September 7, 2022, approximately five plaintiffs. The complaints make similar allegations as those described above for the Slater Fire and each seek various damages, including economic damages of approximately \$16 million based on \$1 million for each of the 11 individual plaintiffs and \$5 million for the one non-individual plaintiff across both the *Denny* and *Sparks* complaints. The individual plaintiffs also seek unspecified noneconomic damages. As described above, in June 2024, PacifiCorp reached a settlement totaling \$10 million for 54 plaintiffs in the California and Oregon Slater Fire cases, which resolved the remaining Oregon claims. As a result, the bellwether trial scheduled for September 23, 2024, was vacated.

United States – Loss and Damages to Federal Lands – Slater Fire

PacifiCorp received a notice of indebtedness from the U.S. Department of Agriculture Forest Service ("USFS") indicating that PacifiCorp owes \$356 million for fire suppression costs, natural resource damages and burned area emergency response costs incurred by the USFS associated with the Slater Fire in California. The notice further indicates that the alleged amounts owed may not include all environmental damages to which the USFS may be entitled and which the U.S. may seek to recover if further action is taken to resolve the debt. Additional charges for interest, penalties and administrative costs may also be sought associated with amounts considered overdue. In January 2024, PacifiCorp received correspondence from the U.S. Department of Justice ("USDOJ") indicating its intent to litigate the matter due to PacifiCorp not having paid the \$356 million. PacifiCorp is actively cooperating with the USDOJ on resolving these alleged claims, including through the pursuit of alternative dispute resolution.

2020 Oregon Wildfires, Excluding Slater Fire

As described below, a significant number of complaints on behalf of plaintiffs associated with the 2020 Wildfires have been filed in Oregon in addition to those described above for the Slater Fire. The plaintiffs generally allege: (i) negligence due in part to alleged failure to comply with certain Oregon statutes and administrative rules, including those issued by the OPUC; (ii) gross negligence alleged in the form of willful, wanton and reckless disregard of known risks to the public; (iii) trespass; (iv) nuisance; (v) inverse condemnation; (vi) pre- and post-judgment interest; and (vii) reasonable attorney fees, investigation costs and expert witness fees. The complaints generally assert claims for: (i) noneconomic damages, including mental suffering, emotional distress, inconvenience and interference with normal and usual activities; (ii) damages for real and personal property and other economic losses; (iii) double the amount of property and economic damages; (iv) treble damages for specific costs associated with loss of forestry, trees and shrubbery; and (v) double the damages for the costs of litigation and reforestation. Certain complaints include wrongful death claims as described below. The plaintiffs generally demand a trial by jury and reserve their right to further amend their complaints to allege claims for punitive damages.

On September 30, 2020, a class action complaint against PacifiCorp was filed, captioned *Jeanyne James et al. v. PacifiCorp*, Case No. 20CV33885, ("*James*") in Multnomah County Circuit Court Oregon. The complaint was filed by Oregon residents and businesses who sought to represent a class of all Oregon citizens and entities whose real or personal property was harmed beginning on September 7, 2020, by wildfires in Oregon allegedly caused by PacifiCorp. On November 3, 2021, the plaintiffs filed an amended complaint to limit the class to include Oregon citizens allegedly impacted by the Echo Mountain Complex, South Obenchain, 242 and Santiam Canyon fires, as well as to add claims for noneconomic damages. The amended complaint alleged that PacifiCorp's assets contributed to the Oregon wildfires occurring on or after September 7, 2020, and that PacifiCorp acted with gross negligence, among other things. The amended complaint seeks damages similar to those described above, including not less than \$600 million of economic damages and in excess of \$1 billion of noneconomic damages for the plaintiffs and the class. Numerous cases have been consolidated into *James* as described below.

On April 29, 2024, May 16, 2024, May 31, 2024, July 31, 2024, September 11, 2024 and January 14, 2025, six separate mass complaints against PacifiCorp naming 1,000, 100, 265, 78, 93 and 55 individual class members, respectively, were filed in Multnomah County Circuit Court Oregon captioned *Shane A Henson et al. v. PacifiCorp*, *Karen Andersen et al. v. PacifiCorp*, *Vanessa Alexander et al. v. PacifiCorp*, *Emily Broderick et al. v. PacifiCorp*, *Sergio Garcia Montes et al. v. PacifiCorp* and *Butte Falls Family Ranch, LLC*, respectively, each referencing *James* Case No. 20CV33885 as the lead case. Complaints for five of the plaintiffs in the mass complaints were subsequently dismissed. The *James* mass complaints make damages-only allegations seeking for each individual class member \$5 million of economic damages, \$25 million of noneconomic damages and punitive damages equal to 0.25 times the amount of economic and noneconomic damages. The *James* mass complaints also assert doubling of economic damages for each individual class member. The class members demand a trial by jury. Refer to "*James* Court Activity" section below for information regarding additional damages phase trials.

On December 31, 2024, a complaint against PacifiCorp was filed, captioned *Frank Timber Resources, Inc. et al. v. PacifiCorp*, referencing the *James* case number as the lead case, ("*Frank Timber*") in Multnomah County Circuit Court Oregon by four plaintiffs. Similar to the mass complaints described above, the complaint makes damages-only allegations seeking approximately \$12 million of economic damages, doubling of economic damages and punitive damages equal to 0.25 times the amount of economic damages. The plaintiffs demand a trial by jury.

On December 31, 2024, a complaint against PacifiCorp was filed, captioned *Theodore and Deana Freres et al. v. PacifiCorp*, referencing the *James* case number as the lead case, ("*Theodore and Deana Freres*") in Multnomah County Circuit Court Oregon by four plaintiffs. Similar to the mass complaints described above, the complaint makes damages-only allegations seeking approximately \$1 million of economic damages, doubling of economic damages and punitive damages equal to 0.25 times the amount of economic damages. The plaintiffs demand a trial by jury.

As a result of the six mass complaints, subsequent dismissals and the two additional complaints filed in December 2024 with respect to the *James* case described above, active class plaintiffs in *James* total 1,594 for which per plaintiff damages sought vary. As described below under "*James* Court Activity," class plaintiffs selected for trial are required to amend their complaints to address facts specific to their complaints, generally resulting in updates to the amount of economic and noneconomic damages sought. Damages specified in the original mass complaints remain applicable to substantially all of the class plaintiffs.

James Trial Activity

On April 24, 2023, the jury trial for *James* with respect to the 17 named plaintiffs began in Multnomah County Circuit Court Oregon. In June 2023, the jury issued its verdict finding PacifiCorp liable to the 17 named plaintiffs and to the class with respect to the four wildfires. The jury found PacifiCorp's conduct grossly negligent, reckless and willful as to each plaintiff and the entire class. The jury awarded the 17 named plaintiffs \$90 million of damages, including \$4 million of economic damages, \$68 million of noneconomic damages and \$18 million of punitive damages based on a 0.25 multiplier of the economic and noneconomic damages.

In September 2023, the Multnomah County Circuit Court Oregon ordered trial dates for three damages phase trials described below wherein plaintiffs in each of the three damages phase trials would present evidence regarding their damages.

In January 2024, the Multnomah County Circuit Court Oregon entered a limited judgment and money award for the June 2023 *James* verdict. The limited judgment awards \$92 million of damages based on the amounts awarded by the jury, as well as doubling of the economic damages and offsetting of any insurance proceeds received by plaintiffs. The limited judgment created a lien against PacifiCorp, attaching a debt for the money awards. PacifiCorp posted a supersedeas bond, which stays any effort to seek payment of the judgment pending final resolution of any appeals. Under Oregon Revised Statutes 82.010, interest at a rate of 9% per annum will accrue on the judgment commencing at the date the judgment was entered until the entire money award is paid, amended or reversed by an appellate court. In January 2024, PacifiCorp filed a notice of appeal associated with the June 2023 verdict in *James*, including whether the case can proceed as a class action and filed a motion to stay further damages phase trials. On February 14, 2024, the Oregon Court of Appeals denied PacifiCorp's request to stay the damages phase trials. On February 13, 2024, the 17 named plaintiffs filed a notice of cross-appeal as to the January 2024 limited judgment and money award. The appeals process and further actions could take several years.

In January 2024, the jury for the first *James* damages phase trial awarded nine plaintiffs \$62 million of damages, including \$6 million of economic damages and \$56 million of noneconomic damages. After the jury verdict, the Multnomah County Circuit Court Oregon doubled the economic damages to \$12 million and added \$16 million of punitive damages using the 0.25 multiplier determined by the jury for the June 2023 *James* verdict, bringing the total damages awarded to \$84 million. PacifiCorp requested that the Multnomah County Circuit Court Oregon judge offset the damage awards by deducting insurance proceeds received by any of the nine plaintiffs, and on March 25, 2024, the Multnomah County Circuit Court Oregon granted in large part the offset request. In April 2024, the Multnomah County Circuit Court Oregon entered a limited judgment and money award for the January 2024 *James* verdict. The limited judgment awards \$80 million of damages based on the amounts awarded by the jury and offsetting insurance proceeds received by plaintiffs. The limited judgment created a lien against PacifiCorp, attaching a debt for the money awards. In April 2024, PacifiCorp posted a supersedeas bond, which stays any effort to seek payment of the judgment pending final resolution of any appeals. PacifiCorp amended its January 2024 appeal of the June 2023 *James* verdict to include the January 2024 jury verdict.

In March 2024, the jury for the second *James* damages phase trial awarded ten plaintiffs \$42 million of damages, including \$12 million of doubled economic damages, \$23 million of noneconomic damages and \$7 million of punitive damages using the 0.25 multiplier determined by the jury for the June 2023 *James* verdict. PacifiCorp requested that the Multnomah County Circuit Court Oregon judge offset the damage awards by deducting insurance proceeds received by any of the ten plaintiffs and on May 6, 2024, the Multnomah County Circuit Court Oregon granted the offset request. In June 2024, the Multnomah County Circuit Court Oregon entered a limited judgment and money award for the March 2024 *James* verdict. The limited judgment awards \$38 million of damages based on the amounts awarded by the jury and offsetting insurance proceeds received by plaintiffs. The limited judgment created a lien against PacifiCorp, attaching a debt for the money awards. In July 2024, PacifiCorp posted a supersedeas bond, which stays any effort to seek payment of the judgment pending final resolution of any appeals. PacifiCorp further amended its appeal of the June 2023 *James* verdict to include the March 2024 jury verdict.

In February 2025, the jury for the third *James* damages phase trial described below under "*James* Court Activity" awarded seven plaintiffs \$32 million of noneconomic damages in addition to \$4 million of economic damages stipulated for eight plaintiffs prior to the trial. In accordance with Oregon law, plaintiffs asked the court to double the economic damages to \$8 million after the verdict. PacifiCorp expects the court will award the doubling of economic damages and also increase the award for \$9 million in punitive damages by applying the 0.25 multiplier of economic and noneconomic damages consistent with the June 2023 *James* verdict. As a result, PacifiCorp expects the total award for the eight plaintiffs to be approximately \$49 million. PacifiCorp filed post-trial motions with the Multnomah County Circuit Court Oregon requesting the court offset the damage awards by deducting insurance proceeds received by any of the eight plaintiffs. PacifiCorp intends to appeal the jury's damage awards associated with the February 2025 jury verdict once judgment is entered.

PacifiCorp's opening brief is due to be filed with the Oregon Court of Appeals on or before February 25, 2025, in connection with its appeal of the June 2023 *James* verdict and the January and March 2024 verdicts for the first two *James* damages phase trials.

Additional damages phase trials have been scheduled in 2025 as described below.

James Court Activity

On May 31, 2024, plaintiffs' counsel in *James* filed a motion to enter a case management order that requests the creation of a special docket to establish a trial process through which up to five consolidated damages trials for collectively 50 class members would occur each month going forward. PacifiCorp opposed the motion and filed a competing motion on June 26, 2024. On October 2, 2024, the Multnomah County Circuit Court Oregon issued a case management order and identified discovery, pleading and other deadlines applicable to nine damages phase trials to be held in 2025. The trials will adjudicate the damages of up to 10 plaintiffs per trial starting February 3, March 24, April 21, May 12, June 2, July 7, September 9, October 6, and December 7, 2025. The case management order allows the plaintiffs to select three need-based plaintiffs per trial using the following criteria: (i) the plaintiff is of advanced age, specifically seventy years of age or older and/or (ii) the plaintiff is suffering from sickness or illness that may impede their ability to participate in a later trial. The Multnomah County Circuit Court Oregon will randomly select the other seven plaintiffs. Plaintiffs have been selected for the first six trials, and plaintiffs for the remaining three trials are scheduled to be selected on February 28, 2025. The jury verdict for the first of the additionally scheduled nine damages phase trials was issued in February 2025, as described above. Within ten days after the verdict is rendered in the April 21 trial, and within 30 days after the verdict is rendered in the July 7 and December 7 trials, respectively, the parties are required to engage in global mediation with the objective of resolving the claims of the remaining absent class members.

On June 13, 2024, plaintiffs' counsel for the plaintiffs who have opted out of the *James* class filed a motion for the court to issue an order clarifying the scope of lead counsel in the damages phase to unrepresented members of the *James* class members. The opt-out plaintiffs' counsel describes in the motion its ability to have negotiated settlements for opt-out plaintiffs, bringing immediate financial relief and indicates that lead counsel for the class has placed its interests above those of the individuals they represent. On September 6, 2024, the Multnomah County Circuit Court Oregon denied in part the opt-out plaintiffs' counsel's motion to clarify the scope of lead counsel in the damages phase. Specifically, the Multnomah County Circuit Court Oregon ruled that lead counsel continue to represent absent class members "regardless of whether or not the absent class members have signed a retainer agreement with lead counsel." However, the Multnomah County Circuit Court Oregon clarified that absent class members could choose different legal representation, but each absent class member would have to expressly apply to the Multnomah County Circuit Court Oregon to be excluded from further representation by lead counsel and to terminate any ongoing attorney-client relationship. Plaintiffs' counsel filed motions with the Multnomah County Circuit Court Oregon for substitution of lead counsel for nearly 1,300 *James* class members, including several plaintiffs included in the *James* mass complaints. In December 2024, the first substitution motion covering approximately 700 plaintiffs was granted.

On September 13, 2024, PacifiCorp filed a motion to make the *James* mass complaints more definite and certain. On October 4, 2024, in response to PacifiCorp's motion, the Multnomah County Circuit Court Oregon issued an order granting, in part, the motion. The order requires the plaintiffs selected for the nine damages phase trials scheduled in 2025 to file amended complaints alleging the specific facts that support their claims for economic and noneconomic damages. To date, no amended complaints seek damages in excess of the amounts sought in the original mass complaints.

James Consolidated Cases

The following cases have been consolidated into the *James* case:

Amended *Salter* filed August 20, 2021, in Multnomah County Circuit Court Oregon by approximately 97 individuals. The complaint seeks damages similar to those described above, including economic damages not to exceed \$150 million and noneconomic damages not to exceed \$500 million.

Amended *Allen* filed September 2, 2021, in Multnomah County Circuit Court Oregon by approximately five individuals. The *Allen* case seeks damages similar to those described above, including \$8 million in economic and \$24 million in noneconomic damages related to the Beachie Creek Fire.

Cady filed April 26, 2022, in Multnomah County Circuit Court Oregon. The *Cady* case was filed by 21 individuals seeking approximately \$105 million in economic damages based on \$5 million per each of the 21 individual plaintiffs in connection with the Echo Mountain Complex Fire. The individual plaintiffs also seek noneconomic damages to be determined at trial. In March 2024, a settlement was reached resulting in cancellation of the jury trial that was previously scheduled to begin May 6, 2024.

Dietrich filed August 26, 2022, in Multnomah County Circuit Court Oregon. The complaint, as amended on September 6, 2022, was filed by six Oregon residents individually and on behalf of a class defined to include residents of, business owners in, real or personal property owners in and any other individuals physically present in specified Oregon counties as of September 7, 2020 who experienced any harm, damage or loss as a result of the Santiam Canyon, Echo Mountain Complex, 242 or South Obenchain fires. The amended complaint seeks \$400 million in economic damages and \$500 million in noneconomic damages. The *Dietrich* case is currently stayed due to plaintiffs' motion to consolidate the case into *James*.

Freres Timber filed September 1, 2022, in Multnomah County Circuit Court Oregon. The complaint, as amended on October 18, 2023, was filed by three commercial plaintiffs seeking approximately \$7 million in economic damages and \$2 million of punitive damages. In March 2024, a settlement was reached, and the jury trial scheduled for April 2024 was cancelled.

Logan filed September 2, 2022, in Multnomah County Circuit Court Oregon. The Logan case was filed by five individuals seeking approximately \$35 million in economic damages based on \$5 million for each of the four individual plaintiffs and \$15 million for the one non-individual plaintiff. In March 2024, a settlement was reached resulting in cancellation of the jury trial that was previously scheduled to begin May 6, 2024.

Bell filed September 7, 2022, in Multnomah County Circuit Court Oregon by 59 plaintiffs seeking \$35 million in damages, including economic and noneconomic damages.

CW Specialty Lumber, Inc. filed December 6, 2022, in Multnomah County Circuit Court Oregon. The complaint, as amended on October 17, 2023, was filed by two commercial timber plaintiffs each seeking approximately \$10 million in economic damages and \$3 million in punitive damages. In March 2024, a settlement was reached, and the jury trial scheduled for April 2024 was cancelled.

The settlements reached with plaintiffs in the various *James* consolidated cases in March 2024 described above totaled \$29 million.

Ashley Andersen et al. v. PacifiCorp and Consolidated Cases

On November 16, 2021, a complaint against PacifiCorp was filed, captioned *Ashley Andersen et al. v. PacifiCorp*, Case No. 21CV36567, ("*Andersen*") in Multnomah County Circuit Court Oregon. The *Andersen* case was filed by approximately 50 Oregon residents, occupants and real and personal property owners who allege injuries and damages resulting from the September 2020 Echo Mountain Complex Fire. The *Andersen* case as amended on December 6, 2022, makes allegations similar to those described above and seeks economic damages of approximately \$83 million and noneconomic damages of approximately \$83 million. Multiple complaints have been consolidated into *Andersen* with all associated complaints filed to date settled but for one plaintiff as described below.

The following complaints also filed in Multnomah County Circuit Court Oregon have been consolidated into the *Andersen* case each with allegations and damages similar to those described above for the *Andersen* case and each seek economic damages of approximately \$83 million and noneconomic damages of approximately \$83 million unless otherwise noted: *Sparks* filed December 17, 2021 and amended on September 7, 2022, approximately 49 plaintiffs, various damages of approximately \$125 million; *Russie* filed May 13, 2022, approximately 45 plaintiffs, various damages of approximately \$125 million; *Klinger* filed September 1, 2022, approximately 49 plaintiffs; *Bowen* filed September 1, 2022, approximately 47 plaintiffs; *Weathers* filed September 1, 2022, approximately 46 plaintiffs; *Barnholdt* filed September 6, 2022, approximately 26 plaintiffs; *Pratt* filed September 7, 2022, approximately 16 plaintiffs; *Thompson* filed September 7, 2022, approximately 49 plaintiffs; *Cohn* filed September 7, 2022, approximately 6 plaintiffs, \$5 million for a wrongful death claim, \$15 million in economic damages and \$15 million in noneconomic damages.

On June 9, 2023, a complaint against PacifiCorp was filed by the same plaintiff group as *Andersen*, captioned *Annamarie Miller et al. v. PacifiCorp*, Case No. 23CV23104, in Multnomah County Circuit Court Oregon by approximately 10 plaintiffs, seeking approximately \$42 million in economic damages and \$42 million in noneconomic damages associated with the Echo Mountain Complex Fire and makes allegations similar to those described above.

On May 31, 2024, PacifiCorp reached a settlement totaling \$178 million with approximately 400 plaintiffs associated with the Echo Mountain Complex and Beachie Creek fires who opted out of the *James* class. The settlement resolved the *Andersen* consolidated cases and the *O'Keefe* consolidated cases described below but for three remaining plaintiffs. The settlement payments were made in July 2024.

Judith O'Keefe v. PacifiCorp and Consolidated Cases

On April 23, 2021, a complaint against PacifiCorp was filed, captioned *Judith O'Keefe v. PacifiCorp*, Case No. 21CV15857 ("*O'Keefe*") in Multnomah County Circuit Court Oregon associated with the Beachie Creek Fire. The complaint, as amended on January 31, 2024, was filed by one individual plaintiff seeking damages similar to those described above, including approximately \$1 million in economic damages and \$1 million in noneconomic damages.

The following cases also associated with the Beachie Creek Fire were consolidated into the *O'Keefe* case: *Macy-Wyngarden* filed September 1, 2022, in Multnomah County Circuit Court Oregon by approximately 12 plaintiffs seeking economic damages of approximately \$83 million and noneconomic damages of approximately \$83 million; *Bogle* filed September 1, 2022, in Multnomah County Circuit Court Oregon by approximately 39 plaintiffs seeking economic damages of approximately \$83 million and noneconomic damages of approximately \$83 million; *Dodge* filed September 8, 2022, in Multnomah County Circuit Court Oregon by two plaintiffs seeking \$3 million in economic damages and \$3 million in noneconomic damages.

The consolidated *O'Keefe* cases were settled along with the consolidated *Andersen* cases described above.

Other Cases

On October 7, 2021, a complaint against PacifiCorp was filed, captioned *Estate of Cathy Lynn Cook et al. v. PacifiCorp et al.*, Case No. 21CV35076, ("*Cook*") in Multnomah County Circuit Court Oregon by approximately two plaintiffs, seeking a minor amount of economic damages and approximately \$40 million in noneconomic damages associated with the Beachie Creek Fire, and makes allegations similar to those described above and includes wrongful death claims. On February 5, 2024, the complaint was amended to add a request for \$200 million in punitive damages.

On October 7, 2021, a complaint against PacifiCorp was filed, captioned *Angela Mosso et al. v. PacifiCorp et al.*, Case No. 21CV35069, ("*Mosso*") in Multnomah County Circuit Court Oregon by approximately four plaintiffs, seeking approximately \$10 million in economic damages and \$90 million in noneconomic damages associated with the Beachie Creek Fire, and makes allegations similar to those described above and includes wrongful death claims. On February 5, 2024, the complaint was amended to add a request for \$400 million in punitive damages. On April 18, 2024, a second amended complaint was filed increasing noneconomic damages to \$200 million and decreasing punitive damages to \$330 million for total damages sought of \$540 million.

In April 2024, the Multnomah County Circuit Court Oregon denied plaintiffs' motions for summary judgment in *Cook* and *Mosso* to use the June 2023 verdict in *James* to establish fire causation and negligence for the *Cook* and *Mosso* trials. In June 2024, PacifiCorp settled the *Cook* and *Mosso* cases and the associated jury trials previously scheduled in July and August 2024 were cancelled.

On September 1, 2022, a complaint against PacifiCorp associated with the Archie Creek Fire was filed, captioned *Leonard Mitchell Lee et al. v. PacifiCorp*, Case No. 22CV29685, ("*Lee*") in Multnomah County Circuit Court Oregon by approximately five plaintiffs, seeking approximately \$25 million in economic and noneconomic damages and makes allegations similar to those described above. No trial date has been set. In June 2024, PacifiCorp reached an agreement in principle with three of the *Lee* plaintiffs, but the case remains pending while PacifiCorp and the court determine whether the remaining two plaintiffs wish to pursue their claims.

On September 2, 2022, a complaint against PacifiCorp associated with the Archie Creek Fire was filed, captioned *Beamer et al. v. PacifiCorp*, Case No. 22CV29851, ("*Beamer*") in Oregon Circuit Court in Douglas County, Oregon ("Douglas County Circuit Court Oregon"), by approximately 36 plaintiffs, seeking more than \$190 million in economic damages based on \$5 million for each of the 35 individual plaintiffs and \$15 million for the one non-individual plaintiff and makes allegations similar to those described above. The individual plaintiffs also seek noneconomic damages to be determined at trial. In December 2023, claims associated with approximately 27 plaintiffs in the *Beamer* case were settled. In February 2024, the Douglas County Circuit Court Oregon dismissed all but one remaining plaintiff. In April 2024, in response to the one remaining plaintiff in *Beamer* filing a letter indicating the intent to dismiss their claims, the Douglas County Circuit Court Oregon entered the dismissal.

A group of subrogation insurers that filed complaints against PacifiCorp associated with the Archie Creek Fire agreed to a mediator's proposal under which PacifiCorp will pay 51.75% of the total claims paid and to be paid by the carriers related to the Archie Creek Fire. In October 2022, PacifiCorp paid \$24 million to the subrogation insurers. During 2023 and January 2024, PacifiCorp paid additional amounts to the subrogation insurers and ultimately expects to pay a total of \$28 million to the subrogation insurers. While some of the subrogation complaints have been fully dismissed, the following remain active:

The *Lexington* complaint was filed against PacifiCorp by two insurers in Douglas County Circuit Court Oregon seeking \$14 million in damages for negligence associated with the Archie Creek Fire and, as amended on February 3, 2022, makes allegations similar to those described above. The *Lexington* case was partially dismissed following settlement, but general judgment of dismissal has not yet been entered because certain plaintiffs remain active.

The *Certain Underwriters* complaint was filed against PacifiCorp by four insurers in Douglas County Circuit Court Oregon on April 28, 2022, by multiple insurers seeking \$14 million in damages for negligence associated with the Archie Creek Fire. The *Certain Underwriters* case has now been fully dismissed.

The *Ace American Insurance Co.* complaint was filed against PacifiCorp in Douglas County Circuit Court Oregon on August 25, 2022, by 15 insurers seeking approximately \$24 million for negligence. The *Ace American Insurance* case was partially dismissed following settlement, but general judgment of dismissal has not yet been entered because certain plaintiffs remain active.

On September 1, 2022, a complaint against PacifiCorp was filed, captioned *Stroh Coastal Holdings LLC v. PacifiCorp*, Case No. 22CV29695, ("*Stroh Coastal*") in Multnomah County Circuit Court Oregon by one plaintiff, seeking \$1 million in economic damages associated with the Pike Road Fire and makes allegations similar to those described above. The *Stroh Coastal* case was previously set for trial starting September 3, 2024. On July 2, 2024, PacifiCorp settled the *Stroh Coastal* case.

In January 2024, PacifiCorp settled various claims for \$3 million with approximately 14 plaintiffs associated with various 2020 Wildfire complaints in Oregon.

Winery Cases

Certain Oregon vineyards have filed five lawsuits alleging economic damages associated with the 2020 Labor Day Fires. See *Cooper Mountain Winery LLC v. PacifiCorp*, Case No. 23CV47202; *Sokol Blosser, Ltd. et. al v. PacifiCorp*, Case No. 24CV03044; *Elk Cove Vineyards, Inc. v. PacifiCorp*, Case No. 23CV28258; *Willamette Valley Vineyards Inc v. PacifiCorp*, Case No. 23CV29519; and *Lange Winery LLC, et al. v. PacifiCorp*, Case No. 24CV25661. Plaintiffs dismissed two earlier-filed cases (*Retraite, LLC, et. al v. PacifiCorp*, Case No. 23CV28213 and *Brigadoon Vineyards, LLC v. PacifiCorp*, Case No. 23CV28149) and refiled them in the *Lange Winery* case described below. All of the cases are in the initial stages of discovery. Additional details are provided below.

On July 14, 2023, a complaint against PacifiCorp was filed, captioned *Elk Cove Vineyards, Inc. v. PacifiCorp*, Case No. 23CV28258, in Oregon Circuit Court in Yamhill County, Oregon, by one plaintiff, seeking approximately \$3 million in economic damages associated with multiple fires and makes allegations similar to those described above. On March 13, 2024, the complaint was amended to add 12 plaintiffs, with all plaintiffs collectively seeking approximately \$25 million in economic damages. The *Elk Cove Vineyards, Inc.* case is set for trial starting March 2, 2026 through March 31, 2026.

On July 14, 2023, a complaint against PacifiCorp was filed, captioned *Retraite, LLC et al. v. PacifiCorp*, Case No. 23CV28213, in Oregon Circuit Court in Polk County, Oregon, by approximately four plaintiffs, seeking approximately \$4 million in economic damages associated with multiple fires and makes allegations similar to those described above. Plaintiffs dismissed this case and included these wineries in the newly filed *Lange Winery* case described below.

On July 14, 2023, a complaint against PacifiCorp was filed, captioned *Brigadoon Vineyards, LLC v. PacifiCorp*, Case No. 23CV28149, in Oregon Circuit Court in Lane County, Oregon, seeking approximately \$100,000 in economic damages associated with multiple fires and makes allegations similar to those described above. Plaintiffs dismissed this case and included these wineries in the newly filed *Lange Winery* case described below.

On July 24, 2023, a complaint against PacifiCorp was filed, captioned *Willamette Valley Vineyards Inc v. PacifiCorp*, Case No. 23CV29519, in Oregon Circuit Court in Marion County, Oregon, seeking approximately \$3 million in economic damages associated with multiple fires and makes allegations similar to those described above. On March 29, 2024, the complaint was amended to add four plaintiffs, with all plaintiffs collectively seeking approximately \$4 million in economic damages. On February 3, 2025, the complaint was further amended to add an unspecified amount of punitive damages. The *Willamette Valley Vineyards Inc* case is set for trial starting January 12, 2026 through February 6, 2026.

On November 7, 2023, a complaint against PacifiCorp was filed, captioned *Cooper Mountain Winery LLC v. PacifiCorp*, Case No. 23CV47202, in Oregon Circuit Court in Washington County, Oregon, seeking approximately \$750,000 in economic damages associated with multiple fires and makes allegations similar to those described above. The *Cooper Mountain Winery LLC* case is set for trial November 4, 2025, through November 28, 2025. Plaintiffs dismissed this case.

On January 18, 2024, a complaint against PacifiCorp was filed, captioned *Sokol Blosser, Ltd. et al. v. PacifiCorp*, Case No. 24CV03044, ("*Sokol Blosser*") in Multnomah County Circuit Court Oregon by approximately nine plaintiffs, seeking approximately \$20 million in economic damages associated with multiple fires and makes allegations similar to those described above. On October 1, 2024, the complaint was amended to add 25 plaintiffs with all plaintiffs collectively seeking approximately \$90 million in economic damages. The *Sokol Blosser* case is set for trial starting November 3, 2025 through December 9, 2025.

On May 24, 2024, a complaint against PacifiCorp was filed, captioned *Lange Winery LLC et al. v. PacifiCorp*, Case No. 24CV25661, ("*Lange Winery*") in Multnomah County Circuit Court Oregon by approximately 36 plaintiffs, seeking approximately \$51 million in economic damages associated with multiple fires and makes allegations similar to those described above. The *Lange Winery* case is set for trial starting May 4, 2026, through June 12, 2026.

On October 31, 2024, a complaint against PacifiCorp was filed, captioned *The Lumos Wine Co. et al. v. PacifiCorp*, Case No. 24CV51872, ("*Lumos*") in Multnomah County Circuit Court Oregon by approximately six plaintiffs, seeking approximately \$2 million in economic damages associated with multiple fires and makes allegations similar to those described above.

United States and State of Oregon – Loss and Damages to Federal and State Lands – Oregon Fires

In 2023, PacifiCorp received correspondence from the USDOJ, representing the U.S. Department of the Interior, Bureau of Land Management, Bureau of Indian Affairs, USFS, regarding the potential recovery of certain costs and damages alleged to have occurred to federal lands from the September 2020 Archie Creek and Susan Creek fires. The USDOJ provided a damages estimate of approximately \$625 million for mediation purposes only, which included costs and damages relating to damaged timber and improvements; reforestation; coordination with hydropower license, suppression costs and other assessment costs; and cleanup and rehabilitation costs. The amounts alleged for natural resource damage from these fires do not include intangible environmental and natural resource damages that the U.S. could potentially seek to recover if this matter was fully litigated, nor do they include multipliers which the agencies are allegedly entitled to collect under pertinent federal regulations, under which, for example, minimum damages for trespass to timber managed by the U.S. Department of Interior are twice the fair market value of the resource at the time of the trespass, or three times if the violation was willful. While PacifiCorp participated in mediation with the USDOJ and continues to seek resolution of the dispute, the USDOJ filed a formal complaint against PacifiCorp as described below.

In 2023, PacifiCorp also received correspondence from the Oregon Department of Justice ("ODOJ"), representing the State of Oregon, regarding the potential recovery of losses and damages to state lands from the Archie Creek and Susan Creek fires. The ODOJ provided a damage estimate of approximately \$109 million for mediation purposes only, which included losses and damages relating to the sheltering of, and assistance to, affected Oregonians; fire control and extinguishment costs; timber damage across 39 acres of Oregon forestland; losses and damages at the Rock Creek Fish Hatchery; road and highway damages; and other costs.

In December 2024, in conjunction with the USDOJ correspondence for the Archie Creek fire described above, a complaint against PacifiCorp was filed, captioned the *United States of America v. PacifiCorp*, Case 3:24-cv-2102, in U.S. District Court, District of Oregon, Portland Division, seeking various unquantified damages and a jury trial. The civil cover sheet accompanying the complaint demands damages estimated to exceed \$900 million, which is greater than the damages included in the original correspondence from the USDOJ due to the addition of estimates for intangible environmental and natural resource damages. PacifiCorp responded to the complaint on February 18, 2025.

On October 12, 2023, and December 21, 2023, the Oregon Department of Forestry sent demand notices for fire suppression costs totaling \$2 million for three separate ignition points associated with the 2020 Wildfires. On May 30, 2024, PacifiCorp reached settlement with the Oregon Department of Forestry for suppression costs associated with one of these ignition points for less than \$1 million.

PacifiCorp is actively cooperating with both the USDOJ and ODOJ on resolving these alleged claims.

2022 McKinney Fire

Numerous complaints associated with the 2022 McKinney Fire have been filed in Sacramento County Superior Court California on behalf of over 300 plaintiffs, including multiple insurers, as described below. The complaints generally allege: (i) inverse condemnation; (ii) negligence; (iii) trespass; (iv) nuisance; and (v) violation of certain sections of the California Public Utilities Code and the California Health & Safety Code and seek various damages. The damages sought generally include: (i) economic damages; (ii) noneconomic damages; (iii) doubling or trebling of timber damages; (iv) punitive damages; (v) prejudgment interest; and (vi) attorneys' fees and other costs. Certain complaints include wrongful death claims as described below. The complaints do not specify the amount of damages sought.

On August 16, 2022, a complaint against PacifiCorp was filed, captioned *Bridges et al. v. PacifiCorp*, Case No. 34-2022-00325257 ("*Bridges*") in Sacramento County Superior Court California by approximately three plaintiffs. The following complaints were filed and subsequently consolidated into *Bridges*: *Cogan* filed August 23, 2022, approximately 12 plaintiffs, including a wrongful death claim; *Shoopman* filed August 26, 2022, approximately 61 plaintiffs, including a wrongful death claim; *Lowe* filed September 28, 2022, approximately two plaintiffs; *Fraser* filed November 9, 2022, approximately 170 plaintiffs; *California Fair Plan Association*, filed March 3, 2023, approximately 18 subrogation insurers; *Corrales*, filed April 6, 2023, approximately 30 plaintiffs; *Murleen*, filed April 20, 2023, approximately seven plaintiffs; *Hickey*, filed May 9, 2023, approximately five plaintiffs; *Volckhausen*, filed May 9, 2023, one plaintiff; *Huber*, filed August 21, 2023, approximately five plaintiffs, including two wrongful death claims; *CSAA* filed December 21, 2023, one subrogation insurer; *Insurance Company of Hannover*, filed January 8, 2024, one subrogation plaintiff; *Bartlett*, filed April 25, 2024, approximately 28 plaintiffs; *Evanston Insurance Company*, filed May 3, 2024, one subrogation plaintiff; *Justice*, filed July 15, 2024, approximately 192 plaintiffs; *Coolidge*, filed July 19, 2024, approximately two plaintiffs; *Sharon Andersen*, filed July 22, 2024, approximately 23 plaintiffs, including a wrongful death claim; *Billingsley*, filed July 25, 2024, approximately 22 plaintiffs, including a wrongful death claim; *Howe*, filed July 25, 2024, approximately 51 plaintiffs; *Cloutman*, filed July 26, 2024, approximately 114 plaintiffs; *Bolden*, filed July 26, 2024, approximately seven plaintiffs; *Rainey*, filed July 26, 2024, approximately 29 plaintiffs, including a wrongful death claim; *Hegler*, filed July 29, 2024, approximately three plaintiffs; *Meier*, filed July 29, 2024, approximately 203 plaintiffs; and *Propp*, filed August 5, 2024, approximately six plaintiffs. In May 2024, the *CSAA* complaint was settled as part of an aggregate settlement with subrogation insurers. A bellwether trial in *Bridges* is scheduled to begin June 16, 2025. Trial for the wrongful death claim in *Huber* is scheduled to begin August 4, 2025.

On December 21, 2022, a complaint against PacifiCorp was filed, captioned *Siskiyou County v. PacifiCorp*, Case No. 2:22-CV-02278-DMC, in the U.S. District Court for the Eastern District of California on behalf of a single plaintiff. A jury trial was scheduled for September 22, 2025. On May 15, 2024, the case settled for \$6 million and the trial date was vacated.

On March 4, 2024, a complaint against PacifiCorp was filed, captioned *Gabriel Hamilton et al. v. PacifiCorp*, Case No. 24CV004099, ("*Hamilton*") in Sacramento County Superior Court California by approximately 34 plaintiffs, including four insurance subrogation plaintiffs. In May 2024, the four insurance subrogation complaints in *Hamilton* were settled as part of an aggregate settlement with subrogation insurers.

On March 28, 2024, a complaint against PacifiCorp was filed, captioned *Mark Crawford et al. v. PacifiCorp*, Case No. 24CV006043, ("*Crawford*") in Sacramento County Superior Court California by approximately 37 plaintiffs. In May 2024, the *Crawford* complaint was settled.

On April 12, 2024, a complaint against PacifiCorp was filed, captioned *Susanne White v. PacifiCorp*, Case No. 2:24-CV-01112-KJM-DMC, ("*White*") in U.S. District Court for the Eastern District of California by one plaintiff.

On April 26, 2024, a complaint against PacifiCorp was filed, captioned *Lynette Marie Adams et al. v. PacifiCorp*, Case No. 24CV008300, ("*Adams*") in Sacramento County Superior Court California by approximately 12 plaintiffs.

In January 2025, PacifiCorp executed settlement agreements totaling \$87 million with 499 individual plaintiffs and \$23 million with personal injury, loss of life and commercial plaintiffs for various complaints associated with the 2022 McKinney Fire.

BERKSHIRE HATHAWAY ENERGY

HomeServices, a subsidiary of BHE, is currently defending against several antitrust cases, all in federal district courts. In each case, plaintiffs claim HomeServices and certain of its subsidiaries (in one instance, HomeServices and BHE) conspired with co-defendants to artificially inflate real estate commissions by following and enforcing multiple listing service ("MLS") rules that require listing agents to offer a commission split to cooperating agents in order for the property to appear on the MLS ("Cooperative Compensation Rule"). None of the complaints specify damages sought. However, two cases allege Texas state law deceptive trade practices claims, for which plaintiffs have asserted damages totaling approximately \$9 billion by separate written notice as required by Texas law. The cases are captioned as follows.

In April 2019, the *Burnett (formerly Sitzler) et al. v. HomeServices of America, Inc. et al.*, Case No. 19CV332, complaint was filed in the U.S. District Court for the Western District of Missouri (the "Burnett case"). This lawsuit, which was certified as a class in April 2022, was originally brought on behalf of named plaintiffs Joshua Sitzler and Amy Winger against the National Association of Realtors ("NAR"), Anywhere Real Estate, HomeServices of America, Inc., RE/MAX, LLC, and Keller Williams Realty, Inc. HSF Affiliates, LLC and BHH Affiliates, LLC, each a subsidiary of HomeServices, were subsequently added as defendants. Rhonda Burnett became a lead class plaintiff in June 2021. The jury trial commenced on October 16, 2023, and the jury returned a verdict for the plaintiffs on October 31, 2023, finding that the named defendants participated in a conspiracy to follow and enforce the Cooperative Compensation Rule, which conspiracy had the purpose or effect of raising, inflating, or stabilizing broker commission rates paid by home sellers. The jury further found that the class plaintiffs had proved damages in the amount of \$1.8 billion. Joint and several liability applies for the co-defendants. Federal law authorizes trebling of damages and the award of pre-judgment interest and attorney fees. Prior to the trial, Anywhere Real Estate and RE/MAX, LLC reached settlement agreements with the plaintiffs. Subsequent to the trial, settlements were reached by Keller Williams, NAR and HomeServices on February 1, 2024, March 15, 2024, and April 25, 2024, respectively. The Anywhere Real Estate, RE/MAX, LLC and Keller Williams settlements received final court approval on May 9, 2024, which has been appealed to the U.S. Court of Appeals for the Eighth Circuit. The NAR and HomeServices settlements received final court approval on November 27, 2024, which also has been appealed to the U.S. Court of Appeals for the Eighth Circuit. The U.S. District Court for the Western District of Missouri entered final judgment on the NAR and HomeServices settlements on January 15, 2025. The final HomeServices settlement agreement with the plaintiffs settles all claims asserted against HomeServices, HSF Affiliates LLC and BHH Affiliates, LLC in the Burnett case and effectuates a nationwide class settlement. The final settlement agreement includes scheduled payments over the next four years aggregating \$250 million. If the settlement is not affirmed by the U.S. Court of Appeals for the Eighth Circuit, HomeServices intends to vigorously appeal on multiple grounds the jury's findings and damage award in the Burnett case, including whether the case can proceed as a class action. The appeals process and further actions could take several years.

In March 2019, the *Christopher Moehrl v. National Association of Realtors, et al. & Sawbill Strategic, Inc. v. HomeServices of America, Inc. et al.*, Case Nos. 19CV01610 and 19CV2544 (together "Moehrl") complaint was filed in the U.S. District Court for the Northern District of Illinois. This certified class action lawsuit was brought on behalf of named plaintiff Christopher Moehrl against the NAR, Anywhere Real Estate, HomeServices of America, Inc., HSF Affiliates, LLC, BHH Affiliates, LLC, Long & Foster Companies, Inc. (also a HomeServices subsidiary), RE/MAX, LLC and Keller Williams Realty, Inc. In February 2025, the court ordered the case stayed as to the HomeServices' defendants pending a decision on the appeal of the HomeServices' nationwide settlement approved in November 2024.

In December 2020, the *Nosalek (formerly Bauman) v. HomeServices of America, Inc. et al.*, Case No. 20CV1244, complaint was filed in the U.S. District Court for the District of Massachusetts. This putative class action lawsuit was originally filed on behalf of named plaintiffs Gary Bauman, Mary Jane Bauman, and Jennifer Nosalek against the MLS Property Information Network, Inc. (MassPIN), Anywhere Real Estate, HomeServices of America, Inc., BHH Affiliates, LLC, HSF Affiliates, LLC, RE/MAX, LLC, Keller Williams Realty, Inc. and additional named defendants. In October 2021, the Baumans voluntarily dismissed themselves from the case, removing them as class representatives. A motion by HomeServices' defendants for summary judgment remains pending based on resolution of the motion for multidistrict litigation. In June 2024, the court ordered the case stayed as to the HomeServices' defendants pending a decision on the appeal of the HomeServices' nationwide settlement approved in November 2024.

In November 2023, the *QJ v. HomeServices of America, Inc. et al.*, Case No. 23CV01013, complaint was filed in the U.S. District Court for the Eastern District of Texas. This putative class action lawsuit was brought on behalf of named plaintiff QJ Team, LLC against the Texas Association of Realtors, Inc., HomeServices of America, Inc., ABA Management, L.L.C. (a HomeServices subsidiary), Ebby Halliday Real Estate, LLC (a HomeServices subsidiary), Keller Williams Realty, Inc. and additional named defendants. In June 2024, the court ordered the case stayed as to the HomeServices' defendants pending a decision on the appeal of the HomeServices' nationwide settlement approved in November 2024.

In December 2023, the *Martin v. HomeServices of America, Inc. et al.*, Case No. 23CV01104, complaint was filed in the U.S. District Court for the Eastern District of Texas. This putative class action lawsuit was brought on behalf of named plaintiff Julie Martin against the Texas Association of Realtors, Inc., HomeServices of America, Inc., ABA Management, L.L.C., Ebby Halliday Real Estate, LLC, Keller Williams Realty, Inc. and additional named defendants. In June 2024, the court ordered the case stayed as to the HomeServices' defendants pending a decision on the appeal of the HomeServices' nationwide settlement approved in November 2024.

On March 21, 2024, the court granted plaintiffs' motion to consolidate the *QJ* case and the *Martin* case.

In December 2023, the *Umpa v. HomeServices of America, Inc. et al.*, Case No. 23CV00945, complaint was filed in the U.S. District Court for the Western District of Missouri. This putative class action lawsuit was brought on behalf of named plaintiff Daniel Umpa against the NAR, HomeServices of America, Inc., BHH Affiliates, LLC, HSF Affiliates, LLC, Long & Foster Companies, Inc., Keller Williams Realty, Inc. and additional named defendants. In April 2024, the court ordered the case stayed as to the HomeServices' defendants pending a decision on the appeal of the HomeServices' nationwide settlement approved in November 2024.

In January 2024, the *Masiello v. Roy H. Long Realty, Inc. d/b/a Long Realty et al.*, Case No. 24CV00045, complaint was filed in the U.S. District Court for the District of Arizona. This putative class action lawsuit was brought on behalf of named plaintiff Joseph Masiello against the Arizona Association of Realtors, Roy H. Long Realty, Inc. d/b/a Long Realty (a HomeServices of America, Inc. subsidiary) and additional named defendants. In July 2024, the court ordered the case stayed as to defendant Long Realty, Inc. pending a decision on the appeal of the HomeServices' nationwide settlement approved in November 2024.

In January 2024, the *Fierro v. BHH Affiliates, LLC, et al.*, Case No. 24CV00449, complaint was filed in the U.S. District Court for the Central District of California. This putative class action lawsuit was brought on behalf of named plaintiffs Gael Fierro and Patrick Thurber against the NAR, Berkshire Hathaway Inc., BHH Affiliates, LLC and additional named defendants. In April 2024, the court ordered the case stayed as to defendant BHH Affiliates, LLC pending a decision on the appeal of the HomeServices' nationwide settlement approved in November 2024.

In January 2024, the *Whaley v. Berkshire Hathaway HomeServices Nevada Properties et al.*, Case No. 24CV00105, amended complaint was filed in the U.S. District Court for the District of Nevada. This putative class action lawsuit was brought on behalf of named plaintiff Nathaniel Whaley against the NAR, Berkshire Hathaway HomeServices Nevada Properties (a HomeServices of America, Inc. subsidiary) and additional named defendants. In May 2024, the court ordered the case stayed as to defendants Berkshire Hathaway HomeServices Nevada Properties and BHH Affiliates, LLC pending a decision on the appeal of the HomeServices' nationwide settlement approved in November 2024.

In February 2024, the *Boykin v. BHH Affiliates, LLC, et al.*, Case No. 24CV00340, complaint was filed in the U.S. District Court for the District of Nevada. This putative class action lawsuit was brought on behalf of named plaintiff Angela Boykin against the NAR, BHH Affiliates, LLC and additional named defendants. In May 2024, the court ordered the case stayed as to defendants Berkshire Hathaway HomeServices Nevada Properties and BHH Affiliates, LLC pending a decision on the appeal of the HomeServices' nationwide settlement approved in November 2024.

On March 20, 2024, the court consolidated the *Boykin* case with the *Whaley* case.

In March 2024, the *Wang v. HomeServices of America, Inc. et al.*, Case No. 24CV02371, complaint was filed in the U.S. District Court for the Southern District of New York. This *pro se* action was filed against the NAR, the Real Estate Board of New York, Inc., and HomeServices of America, Inc., et al. In August 2024, the court ordered the case stayed until November 26, 2024. In February 2025, the court ordered the case stayed as to the HomeServices' defendants pending a decision on the appeal of the HomeServices' nationwide settlement approved in November 2024.

In March 2024, the first amended complaint in the *Gibson v. National Association of Realtors, et al.*, Case No. 23CV00788, complaint was filed in the U.S. District Court for the Western District of Missouri. The putative class action lawsuit was brought on behalf of named plaintiffs Don Gibson, Lauren Criss and John Meiners against the NAR, BHE and additional named defendants. In April 2024, the court ordered the case stayed as to the HomeServices' defendants pending a decision on the appeal of the HomeServices' nationwide settlement approved in November 2024.

On April 23, 2024, the court consolidated the *Gibson* case with the *Umpa* case.

In April 2024, the *Burton v. HomeServices of America, Inc., et al.* Case No. 7:24CV01800, complaint was filed in the U.S. District Court for the District of South Carolina. This putative class action was brought on behalf of named plaintiffs Shauntell Burton, Benny D. Cheatham, Robert Douglass, Douglas Fender, and Dena Fender against HomeServices of America, Inc., HSF Affiliates, LLC, et al. This is the second complaint filed by these plaintiffs; the first complaint was filed against the National Association of Realtors, Keller Williams Realty, Inc. et al. ("Burton I") and is still pending. In June 2024, the court ordered the case stayed as to the HomeServices' defendants pending a decision on the appeal of the HomeServices' nationwide settlement approved in November 2024.

Item 4. Mine Safety Disclosures

Information regarding Berkshire Hathaway Energy's and PacifiCorp's mine safety violations and other legal matters disclosed in accordance with Section 1503(a) of the Dodd-Frank Reform Act is included in Exhibit 95 to this Form 10-K.

PART II

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

BERKSHIRE HATHAWAY ENERGY

BHE's common stock is held by Berkshire Hathaway, and has not been registered with the SEC pursuant to the Securities Act of 1933, as amended, listed on a stock exchange or otherwise publicly held or traded. BHE has not declared or paid any cash dividends to its common shareholders since Berkshire Hathaway acquired an equity interest in BHE in March 2000 and does not presently anticipate that it will declare any dividends on its common stock in the foreseeable future.

PACIFICORP

All common stock of PacifiCorp is held by its parent company, PPW Holdings LLC, which is a direct, wholly owned subsidiary of BHE. PacifiCorp declared and paid dividends to PPW Holdings LLC of \$— million in 2024, \$300 million in 2023 and \$100 million in 2022.

MIDAMERICAN FUNDING AND MIDAMERICAN ENERGY

MidAmerican Funding is an Iowa limited liability company whose membership interest is held solely by BHE. All common stock of MidAmerican Energy is held by its parent company, MHC, which is a direct, wholly owned subsidiary of MidAmerican Funding. MidAmerican Funding declared and paid cash distributions to BHE of \$425 million in 2024, \$1,025 million in 2023 and \$69 million in 2022. MidAmerican Energy declared and paid cash dividends to MHC totaling \$425 million in 2024, \$1,025 million in 2023 and \$275 million in 2022.

NEVADA POWER

All common stock of Nevada Power is held by its parent company, NV Energy, which is an indirect, wholly owned subsidiary of BHE. Nevada Power declared and paid dividends to NV Energy of \$75 million in 2024, \$50 million in 2023 and \$— million in 2022.

SIERRA PACIFIC

All common stock of Sierra Pacific is held by its parent company, NV Energy, which is an indirect, wholly owned subsidiary of BHE. Sierra Pacific declared and paid dividends to NV Energy of \$200 million in 2024, \$100 million in 2023 and \$70 million in 2022.

EASTERN ENERGY GAS

Eastern Energy Gas is a Virginia limited liability corporation whose membership interest is held solely by its parent company, BHE GT&S, which is an indirect, wholly owned subsidiary of BHE. Eastern Energy Gas declared and paid dividends to BHE GT&S of \$361 million in 2024, \$332 million in 2023 and \$— million in 2022.

EGTS

All common stock of EGTS is held by its parent company, Eastern Energy Gas, which is an indirect, wholly owned subsidiary of BHE. EGTS declared and paid dividends to Eastern Energy Gas of \$297 million in 2024, \$158 million in 2023 and \$215 million in 2022.

Item 6. [Reserved]

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

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Berkshire Hathaway Energy Company and its subsidiaries
Consolidated Financial Section

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

The following is management's discussion and analysis of certain significant factors that have affected the consolidated financial condition and results of operations of the Company during the periods included herein. Explanations include management's best estimate of the impact of weather, customer growth, usage trends and other factors. This discussion should be read in conjunction with the Company's historical Consolidated Financial Statements and Notes to Consolidated Financial Statements in Item 8 of this Form 10-K. The Company's actual results in the future could differ significantly from the historical results.

The reportable segment financial information includes all necessary adjustments and eliminations needed to conform to the Company's significant accounting policies. The differences between the reportable segment amounts and the consolidated amounts, described as BHE and Other, relate principally to other corporate entities, corporate functions and intersegment eliminations.

Results of Operations

Overview

Operating revenue and earnings on common shares for the Company's reportable segments for the years ended December 31 are summarized as follows (in millions):

	2024	2023	Change		2023	2022	Change	
Operating revenue:								
PacifiCorp	\$ 6,600	\$ 5,936	\$ 664	11 %	\$ 5,936	\$ 5,679	\$ 257	5 %
MidAmerican Funding	3,251	3,393	(142)	(4)	3,393	4,025	(632)	(16)
NV Energy	4,140	4,523	(383)	(8)	4,523	3,824	699	18
Northern Powergrid	1,627	1,303	324	25	1,303	1,365	(62)	(5)
BHE Pipeline Group	3,810	3,774	36	1	3,774	3,844	(70)	(2)
BHE Transmission	801	799	2	—	799	732	67	9
BHE Renewables	1,475	1,710	(235)	(14)	1,710	1,737	(27)	(2)
HomeServices	4,354	4,322	32	1	4,322	5,268	(946)	(18)
BHE and Other	(138)	(158)	20	(13)	(158)	(137)	(21)	15
Total operating revenue	<u>\$25,920</u>	<u>\$25,602</u>	<u>\$ 318</u>	1 %	<u>\$25,602</u>	<u>\$26,337</u>	<u>\$ (735)</u>	(3)%
Earnings on common shares:								
PacifiCorp	\$ 526	\$ (468)	\$ 994	* %	\$ (468)	\$ 921	\$ (1,389)	* %
MidAmerican Funding	991	980	11	1	980	947	33	3
NV Energy	444	394	50	13	394	427	(33)	(8)
Northern Powergrid	547	165	382	232	165	385	(220)	(57)
BHE Pipeline Group	1,232	1,079	153	14	1,079	1,040	39	4
BHE Transmission	263	246	17	7	246	247	(1)	—
BHE Renewables ⁽¹⁾	447	518	(71)	(14)	518	643	(125)	(19)
HomeServices	(107)	13	(120)	*	13	100	(87)	(87)
BHE and Other	(43)	59	(102)	*	59	(2,035)	2,094	*
Total earnings on common shares	<u>\$ 4,300</u>	<u>\$ 2,986</u>	<u>\$ 1,314</u>	44 %	<u>\$ 2,986</u>	<u>\$ 2,675</u>	<u>\$ 311</u>	12 %

(1) Includes the tax attributes of disregarded entities that are not required to pay income taxes and the earnings of which are taxable directly to BHE.

* Not meaningful.

Earnings on common shares increased \$1,314 million for 2024 compared to 2023. Included in these results was a pre-tax gain in 2024 of \$444 million (\$351 million after-tax) compared to a pre-tax gain in 2023 of \$639 million (\$505 million after-tax) related to the Company's investment in BYD Company Limited ("BYD"). Excluding the impact of this item, adjusted earnings on common shares in 2024 was \$3,949 million, an increase of \$1,468 million, or 59%, compared to adjusted earnings on common shares in 2023 of \$2,481 million.

The increase in earnings on common shares for 2024 compared to 2023 was primarily due to:

- The Utilities' earnings increased \$1,055 million largely due to a decrease in wildfire loss accruals, net of expected insurance recoveries, of \$1,331 million, higher electric utility margin, higher PTCs and increased allowances for equity and borrowed funds used during construction. These items were offset by higher interest expense and increased operations and maintenance expense. Electric retail customer volumes increased 3.6% for 2024 compared to 2023, primarily due to higher customer usage and an increase in the average number of customers, partially offset by the unfavorable impact of weather;
- Northern Powergrid's earnings increased \$382 million, primarily due to higher distribution revenue, the write-off of gas exploration costs in 2023 and lower income tax expense from charges recognized in 2023 related to the Energy Profits Levy income tax and a group relief tax claim recognized in 2024, partially offset by higher distribution-related operating and depreciation and amortization expenses and unfavorable operating performance at the upstream gas exploration and production business. Units distributed increased 0.4% mainly due to the favorable impact of weather;
- BHE Pipeline Group's earnings increased \$153 million, primarily due to the acquisition of an additional 50% limited partner interest in Cove Point on September 1, 2023;
- BHE Renewables' earnings decreased \$71 million, primarily due to lower earnings from the wind tax equity investment portfolio, gains on the extinguishment of debt recognized in 2023 and lower geothermal and natural gas earnings from lower revenue offset by maintenance outages in 2023, partially offset by higher earnings from the retail energy service business, largely due to favorable changes in unrealized positions on derivative contracts;
- HomeServices' earnings decreased \$120 million, primarily due to a charge of approximately \$140 million recognized in the first quarter of 2024 associated with a settlement reached in the ongoing real estate industry litigation matters, partially offset by higher mortgage earnings, mainly due to higher revenue from increases in funded volume and average loan size caused by low inventory driving an increase in average home sales prices, and favorable operating expenses, including lower compensation, marketing and occupancy costs; and
- BHE and Other's earnings decreased \$102 million, primarily due to an unfavorable comparative change of \$154 million related to the Company's investment in BYD, partially offset by lower dividends due to the final redemption of BHE's 4.00% Perpetual Preferred Stock issued to certain subsidiaries of Berkshire Hathaway in December 2023.

Earnings on common shares increased \$311 million for 2023 compared to 2022. Included in these results was a pre-tax gain in 2023 of \$639 million (\$505 million after-tax) compared to a pre-tax loss in 2022 of \$1,950 million (\$1,540 million after-tax) related to the Company's investment in BYD. Excluding the impact of this item, adjusted earnings on common shares in 2023 was \$2,481 million, a decrease of \$1,734 million, or 41%, compared to adjusted earnings on common shares in 2022 of \$4,215 million.

The increase in earnings on common shares for 2023 compared to 2022 was primarily due to:

- The Utilities' earnings decreased \$1,389 million largely due to an increase in wildfire loss accruals, net of expected insurance recoveries, of \$1,613 million, higher operations and maintenance expense, increased interest expense and lower electric utility margin. These items were offset by lower depreciation and amortization expense, higher allowances for equity and borrowed funds used during construction, increased interest and dividend income and favorable changes in the cash surrender value of corporate-owned life insurance policies. Electric retail customer volumes decreased 0.8% for 2023 compared to 2022, primarily due to the unfavorable impact of weather, partially offset by higher customer usage and an increase in the average number of customers;
- Northern Powergrid's earnings decreased \$220 million, primarily due to the write-off of gas exploration costs of \$92 million, unfavorable operating performance at the upstream gas exploration and production business, higher deferred income tax expense, including amounts related to the enactment of a new Energy Profits Levy income tax at the upstream gas exploration and production business, and increased non-service benefit plan costs. Units distributed decreased 3.3% due to the unfavorable impact of weather and lower customer usage;

- BHE Pipeline Group's earnings increased \$39 million primarily due to the impact of a general rate case at Northern Natural Gas and higher earnings from Cove Point, primarily due to the acquisition of an additional 50% limited partner interest in Cove Point on September 1, 2023, partially offset by higher operations and maintenance expense;
- BHE Renewables' earnings decreased \$125 million, primarily due to lower earnings from the wind tax equity investment portfolio, mainly due to lower PTCs, lower earnings from the retail energy service business, largely due to unfavorable changes in unrealized positions on derivative contracts, and lower operating revenue from owned renewable energy projects, partially offset by favorable derivative contract valuations and gains on the extinguishment of debt at owned wind projects;
- HomeServices' earnings decreased \$87 million, primarily due to lower earnings from brokerage, settlement and mortgage services, reflecting the impact of rising interest rates and a corresponding decline in home sales; and
- BHE and Other's earnings increased \$2,094 million, primarily due to a favorable comparative change of \$2,045 million related to the Company's investment in BYD.

Reportable Segment Results

PacifiCorp

Operating revenue increased \$664 million for 2024 compared to 2023, primarily due to higher retail revenues of \$716 million, partially offset by lower wholesale and other revenue of \$52 million. Retail revenue increased primarily due to price impacts of \$554 million from higher average rates, largely from tariff changes, and \$162 million from higher retail volumes. Retail customer volumes increased 3.1%, primarily due to higher customer usage and an increase in the average number of customers, partially offset by the unfavorable impact of weather. Wholesale and other revenue decreased primarily due to lower wholesale volumes and lower average wholesale prices, partially offset by higher wheeling revenue.

Earnings increased \$994 million for 2024 compared to 2023, primarily due to lower wildfire loss accruals, net of expected insurance recoveries, of \$1,331 million, higher utility margin of \$158 million, increased allowances for equity and borrowed funds used during construction of \$109 million and higher interest and dividend income of \$93 million. These items were partially offset by higher interest expense of \$210 million, increased operations and maintenance expense of \$152 million and higher depreciation and amortization expense of \$26 million. Utility margin increased primarily due to higher retail rates and volumes and lower thermal generation costs, partially offset by unfavorable deferred net power costs, higher purchased electricity costs and lower wholesale volumes and average prices. Interest expense increased due to debt issuances in May 2023 and January 2024. Operations and maintenance expenses increased due to increased vegetation management and other wildfire mitigation costs, higher insurance premiums, increased amortization of demand-side management costs, higher legal expenses and increased salary and benefit expenses. Depreciation and amortization expense increased largely due to additional assets placed in-service.

Operating revenue increased \$257 million for 2023 compared to 2022, primarily due to higher retail revenues of \$350 million, partially offset by lower wholesale and other revenue of \$93 million. Retail revenue increased primarily due to price impacts of \$389 million from higher average rates, largely due to tariff changes and sales mix, partially offset by \$39 million from lower retail volumes. Retail customer volumes decreased 0.8%, primarily due to the unfavorable impact of weather and lower customer usage, partially offset by an increase in the average number of customers. Wholesale and other revenue decreased mainly due to lower wholesale volumes, partially offset by higher average wholesale prices.

Earnings decreased \$1,389 million for 2023 compared to 2022, primarily due to higher wildfire loss accruals, net of expected insurance recoveries, of \$1,613 million, higher operations and maintenance expense of \$304 million, increased interest expense of \$115 million due to debt issuances in December 2022 and May 2023, higher property and other taxes of \$20 million and lower utility margin of \$10 million. These items were partially offset by higher allowances for equity and borrowed funds used during construction of \$112 million, increased interest and dividend income of \$54 million, a favorable income tax benefit from valuation changes on state net operating loss carryforwards of \$31 million and favorable changes in the cash surrender value of corporate-owned life insurance policies of \$10 million. Operations and maintenance expense increased due to increased wildfire mitigation and vegetation management costs, higher insurance premiums, increased general and plant maintenance costs and higher legal expenses. Utility margin decreased primarily due to higher purchased electricity costs and lower wholesale and retail volumes, partially offset by higher retail rates, favorable deferred net power costs, lower thermal generation costs and higher average wholesale prices.

MidAmerican Funding

Operating revenue decreased \$142 million for 2024 compared to 2023, primarily due to lower electric operating revenue of \$89 million and lower natural gas operating revenue of \$55 million. Electric operating revenue decreased due to lower wholesale and other revenue of \$65 million and lower retail revenue of \$24 million. Electric wholesale and other revenue decreased mainly due to lower average wholesale prices of \$41 million and lower wholesale volumes of \$25 million. Electric retail revenue decreased primarily due to lower recoveries through adjustment clauses of \$39 million (fully offset in operations and maintenance expense and income tax benefit) and the unfavorable impact of weather of \$12 million, partially offset by higher customer usage of \$24 million. Electric retail customer volumes increased 1.2%, primarily due to an increase in the average number of customers, partially offset by the unfavorable impact of weather. Natural gas operating revenue decreased primarily due to lower energy-related rates of \$84 million (fully offset in cost of sales) from a lower average per-unit cost of natural gas sold and the unfavorable impact of weather of \$8 million, partially offset by higher base rates of \$33 million.

Earnings increased \$11 million for 2024 compared to 2023, primarily due to a favorable income tax benefit, primarily from higher PTCs of \$129 million offset by the effects of ratemaking of \$24 million, higher natural gas utility margin of \$29 million, increased interest and dividend income of \$16 million and higher allowances for equity and borrowed funds used during construction of \$12 million. These items were partially offset by higher depreciation and amortization expense of \$93 million, increased interest expense of \$72 million, higher operations and maintenance expense of \$28 million and lower electric utility margin of \$18 million. Natural gas utility margin increased primarily due to higher base rates from tariff changes, partially offset by the unfavorable impact of weather. Depreciation and amortization expense increased primarily due to additional assets placed in-service and the impacts of certain regulatory mechanisms. Interest expense increased due to debt issuances in September 2023 and January 2024. Operations and maintenance expense increased primarily due to higher general and plant maintenance costs. Electric utility margin decreased primarily due to lower wholesale and retail revenues, partially offset by lower thermal generation and purchased power costs.

Operating revenue decreased \$632 million for 2023 compared to 2022, primarily due to lower natural gas operating revenue of \$317 million and lower electric operating revenue of \$315 million. Natural gas operating revenue decreased due to lower energy-related rates of \$311 million (fully offset in cost of sales) from a lower average per-unit cost of natural gas sold and the unfavorable impact of weather of \$19 million, partially offset by higher base rates of \$11 million. Electric operating revenue decreased due to lower wholesale and other revenue of \$299 million and lower retail revenue of \$16 million. Electric wholesale and other revenue decreased mainly due to lower average wholesale prices of \$203 million and lower wholesale volumes of \$94 million. Electric retail revenue decreased primarily due to lower recoveries through adjustment clauses of \$29 million (fully offset in cost of sales and income tax benefit), partially offset by \$7 million from higher retail volumes and price impacts of \$6 million from changes in sales mix. Electric retail customer volumes increased 1.3%, primarily due to higher customer usage, partially offset by the unfavorable impact of weather.

Earnings increased \$33 million for 2023 compared to 2022, primarily due to lower depreciation and amortization expense of \$260 million and favorable changes in the cash surrender value of corporate-owned life insurance policies of \$39 million, partially offset by lower electric utility margin of \$137 million, an unfavorable income tax benefit from the effects of ratemaking of \$40 million and lower PTCs recognized of \$29 million, increased interest expense of \$29 million due to a September 2023 debt issuance and higher operations and maintenance expense of \$23 million. Depreciation and amortization expense decreased primarily from the impacts of certain regulatory mechanisms, partially offset by additional assets placed in-service. Electric utility margin decreased primarily due to lower wholesale and retail revenues, partially offset by lower purchased power and thermal generation costs. Operations and maintenance expense increased mainly due to higher administrative and other costs, increased general and plant maintenance costs and higher property insurance costs.

NV Energy

Operating revenue decreased \$383 million for 2024 compared to 2023, primarily due to lower electric operating revenue of \$329 million and lower natural gas operating revenue of \$55 million, largely due to lower energy-related rates (fully offset in costs of sales) from a lower average per-unit cost of natural gas sold. Electric operating revenue decreased primarily due to lower fully bundled energy rates (fully offset in cost of sales) of \$463 million, partially offset by higher customer volumes of \$70 million and higher base rates of \$57 million at Nevada Power and Sierra Pacific. Electric retail customer volumes increased 6.5%, primarily due to the favorable impact of weather, an increase in the average number of customers and higher customer usage.

Earnings increased \$50 million for 2024 compared to 2023, primarily due to higher electric utility margin of \$134 million, lower depreciation and amortization of \$61 million and higher allowance for equity and borrowed funds used during construction of \$13 million. These items were partially offset by lower interest and dividend income of \$59 million, higher operations and maintenance expense of \$49 million, increased interest expense of \$32 million and an unfavorable income tax expense primarily due to the effects of ratemaking of \$24 million offset by higher PTCs of \$8 million. Electric utility margin increased primarily due to higher retail volumes and higher base rates at Nevada Power and Sierra Pacific. Depreciation and amortization decreased largely from lower regulatory amortizations. Interest and dividend income decreased mainly from carrying charges on higher deferred energy balances in 2023. Operations and maintenance expenses increased primarily due to higher insurance premiums, increased general and plant maintenance costs and higher salary and benefit expenses. Interest expense increased due to higher debt outstanding.

Operating revenue increased \$699 million for 2023 compared to 2022, primarily due to higher electric operating revenue of \$626 million and higher natural gas operating revenue of \$69 million largely from a higher energy-related rates (fully offset in cost of sales) from a higher average per-unit cost of natural gas sold. Electric operating revenue increased primarily due to higher fully bundled energy rates (fully offset in cost of sales) of \$649 million and higher base rates of \$39 million at Sierra Pacific, partially offset by lower customer volumes of \$44 million and lower regulatory-related revenue deferrals of \$34 million. Electric retail customer volumes decreased 2.6%, primarily due to the unfavorable impact of weather and lower customer usage, partially offset by an increase in the average number of customers.

Earnings decreased \$33 million for 2023 compared to 2022, primarily due to higher depreciation and amortization expense of \$49 million largely due to additional assets placed in-service, increased interest expense of \$38 million due to higher outstanding long-term debt balances and higher average interest rates, higher operations and maintenance expense of \$28 million and lower electric utility margin of \$23 million, partially offset by higher allowances for equity and borrowed funds of \$38 million, increased interest and dividend income of \$30 million, mainly from carrying charges on higher deferred energy balances, and favorable changes in the cash surrender value of corporate-owned life insurance policies of \$12 million. Operations and maintenance expense increased primarily due to higher general and plant maintenance costs and higher customer service operations costs, partially offset by lower earnings sharing accruals at Nevada Power. Electric utility margin decreased primarily due to lower retail customer volumes and lower regulatory-related revenue deferrals, partially offset by higher base rates at Sierra Pacific.

Northern Powergrid

Operating revenue increased \$324 million for 2024 compared to 2023, primarily due to higher distribution revenue of \$288 million and \$45 million from the weaker U.S. dollar, partially offset by lower revenue at the upstream gas exploration and production business of \$21 million due to lower gas production volumes and prices. Distribution revenue increased due to higher tariff rates of \$347 million driven by the impacts of inflation and an increase in units distributed of 0.4% mainly due to the favorable impact of weather, partially offset by lower recoveries of Supplier of Last Resort payments of \$63 million (largely offset in cost of sales).

Earnings increased \$382 million for 2024 compared to 2023, primarily due to higher distribution revenue, the write-off of upstream gas exploration and production costs in 2023 of \$92 million and lower income tax expense from charges recognized in 2023 related to the Energy Profits Levy income tax and a group relief tax claim recognized in 2024, partially offset by higher distribution-related operating and depreciation and amortization expenses of \$38 million and unfavorable operating performance at the upstream gas exploration and production business of \$12 million.

Operating revenue decreased \$62 million for 2023 compared to 2022, primarily due to lower revenue at the upstream gas exploration and production business of \$76 million due to lower gas production volumes and prices, and lower distribution revenue of \$48 million, partially offset by higher revenue at a solar project that commenced commercial operations in July 2022 of \$27 million, higher non-regulated contracting revenue of \$18 million and \$11 million from the weaker U.S. dollar. Distribution revenue decreased primarily due to lower recoveries of Supplier of Last Resort payments of \$47 million (largely offset in cost of sales) and a decrease of 3.3% in units distributed of \$9 million, largely due to the unfavorable impact of weather and lower customer usage, partially offset by higher tariff rates of \$10 million.

Earnings decreased \$220 million for 2023 compared to 2022, primarily due to the write-off of upstream gas exploration and production costs of \$92 million, unfavorable operating performance at the upstream gas exploration and production business of \$79 million, higher deferred income tax expense, including amounts related to the enactment of a new Energy Profits Levy income tax at the upstream gas exploration and production business, increased non-service benefit plan costs of \$35 million and higher distribution-related operating and depreciation expenses of \$18 million, partially offset by higher earnings at a solar project that commenced commercial operations in July 2022 of \$18 million and lower interest expense of \$14 million. The unfavorable operating performance at the upstream gas exploration and production business was largely due to lower gas production volumes and prices.

BHE Pipeline Group

Operating revenue increased \$36 million for 2024 compared to 2023, primarily due to higher operating revenue of \$74 million at Northern Natural Gas and higher non-regulated revenues of \$38 million, partially offset by lower operating revenue of \$55 million at BHE GT&S and \$20 million at Kern River, largely due to a decline in variable transportation revenues from lower rates and volumes. The increase in operating revenue at Northern Natural Gas was primarily due to higher transportation revenue of \$50 million due to higher volumes and rates and higher gas sales of \$23 million from system balancing activities. The decrease in operating revenue at BHE GT&S was primarily due to lower revenues at Cove Point of \$34 million largely from unfavorable variable revenue and storage-related service revenues, a decrease in variable revenue related to natural gas storage park and loan activity of \$18 million at EGTS and lower gas sales of \$15 million at EGTS from operational and system balancing activities, partially offset by an increase in regulated gas transmission and storage services revenue of \$17 million at EGTS largely due to higher volumes.

Earnings increased \$153 million for 2024 compared to 2023, primarily due to higher earnings of \$136 million at BHE GT&S and higher earnings of \$23 million at Northern Natural Gas. The increase at BHE GT&S was primarily due to higher earnings at Cove Point of \$147 million, largely due to the acquisition of an additional 50% limited partner interest in Cove Point on September 1, 2023, decreased cost of gas of \$30 million from the unfavorable revaluation of volumes retained at EGTS in 2023 due to lower natural gas prices and lower operations and maintenance expense of \$23 million largely from lower outside services, partially offset by higher depreciation and amortization of \$16 million, mainly due to additional assets placed in-service, and unfavorable income tax adjustments of \$14 million. The increase at Northern Natural Gas was primarily due to higher transportation revenue and higher margin on gas sales of \$40 million from system balancing activities, partially offset by higher operations and maintenance expense of \$46 million, largely from increased costs for operations projects and increased salary and benefit expenses, and higher depreciation and amortization expense of \$14 million from additional assets placed in-service.

Operating revenue decreased \$70 million for 2023 compared to 2022, primarily due to lower operating revenue of \$164 million at BHE GT&S and \$29 million at Kern River, largely due to a decline in variable transportation revenues from lower rates and volumes, partially offset by higher operating revenue of \$107 million at Northern Natural Gas. The decrease in operating revenue at BHE GT&S was primarily due to lower non-regulated revenue of \$229 million (largely offset in cost of sales) from lower volumes and unfavorable commodity prices and lower volumes at EGTS primarily from the expiration of the Appalachian Gateway Project contracts in August 2022 of \$22 million, partially offset by an increase in regulated gas transportation and storage services rates due to the settlement of EGTS' general rate case of \$49 million, an increase in variable revenue related to natural gas storage park and loan activity of \$17 million at EGTS and higher gas sales of \$15 million at EGTS from operational and system balancing activities. The increase in operating revenue at Northern Natural Gas was largely due to the impacts of a general rate case of \$117 million and higher transportation revenue of \$57 million from higher rates, partially offset by lower gas sales of \$74 million from system balancing activities.

Earnings increased \$39 million for 2023 compared to 2022, primarily due to higher earnings of \$74 million at Northern Natural Gas, partially offset by lower earnings of \$25 million at Kern River, largely due to lower variable transportation revenue, and lower earnings of \$19 million at BHE GT&S. The increase at Northern Natural Gas was primarily due to the impacts of the general rate case of \$79 million and higher transportation revenue, partially offset by higher operations and maintenance expense of \$34 million, an increase in depreciation and amortization expense of \$16 million and unfavorable margin on gas sales from system balancing activities of \$16 million. The decrease at BHE GT&S was primarily due to increased cost of gas of \$72 million from system balancing activities at EGTS and the unfavorable revaluation of volumes retained at EGTS due to lower natural gas prices and higher operations and maintenance expense of \$52 million, partially offset by higher earnings from Cove Point of \$42 million, primarily due to the acquisition of an additional 50% limited partner interest in Cove Point on September 1, 2023, and a \$40 million earnings impact from the rate case settlement at EGTS in 2022. Operations and maintenance expense increased at BHE GT&S mainly due to higher salary and benefit expenses and higher technology and related charges.

BHE Transmission

Operating revenue increased \$2 million for 2024 compared to 2023, primarily due to the recovery of higher costs totaling \$17 million and the favorable impact of the AUC's approved return on equity rate increase of \$17 million at AltaLink, partially offset by lower non-regulated revenue from generating facilities of \$21 million and \$11 million from the stronger U.S. dollar.

Earnings increased \$17 million for 2024 compared to 2023, primarily due to the favorable impact of the AUC's approved return on equity rate increase at AltaLink and higher equity earnings at ETT, partially offset by lower non-regulated revenue from generating facilities and \$3 million from the stronger U.S. dollar.

Operating revenue increased \$67 million for 2023 compared to 2022, primarily due to higher non-regulated revenue from generating facilities of \$85 million, including \$69 million of incremental revenue from wind-powered generating facilities acquired in November 2022, partially offset by \$26 million from the stronger U.S. dollar.

Earnings decreased \$1 million for 2023 compared to 2022, primarily due to \$7 million from the stronger U.S. dollar, partially offset by higher non-regulated revenue from certain generating facilities.

BHE Renewables

Operating revenue decreased \$235 million for 2024 compared to 2023, primarily due to lower natural gas and electric retail energy services revenue of \$172 million, lower geothermal and natural gas revenue of \$80 million due to lower generation and lower pricing and lower wind revenue of \$10 million, partially offset by higher solar revenue of \$25 million from higher generation. Retail energy services revenue decreased mainly due to lower electric and natural gas volumes. Wind revenue decreased largely from unfavorable changes in the valuations of certain derivative contracts and lower pricing, partially offset by higher generation.

Earnings decreased \$71 million for 2024 compared to 2023, primarily due to lower wind earnings of \$73 million, lower geothermal and natural gas earnings of \$37 million from lower revenue offset by maintenance outages in 2023 and lower solar earnings of \$3 million from higher maintenance costs offset by higher revenue. These items were partially offset by higher earnings of \$46 million from the retail energy services business largely due to favorable changes in the unrealized positions on derivative contracts. Wind earnings were unfavorable due to lower earnings from the wind tax equity investment portfolio of \$49 million and lower earnings at owned wind projects of \$24 million, primarily due to gains on the extinguishment of debt recognized in 2023 and lower revenue.

Operating revenue decreased \$27 million for 2023 compared to 2022, primarily due to lower solar and wind revenues of \$78 million, largely from lower generation, and lower natural gas and electric retail energy services revenue of \$56 million, partially offset by favorable changes in the valuations of certain derivative contracts of \$76 million and higher natural gas revenue of \$34 million from favorable generation and pricing. Retail energy services revenue decreased mainly due to unfavorable natural gas pricing, partially offset by an increase in natural gas volumes.

Earnings decreased \$125 million for 2023 compared to 2022, primarily due to lower earnings from the wind tax equity investment portfolio of \$89 million, primarily due to lower PTCs and higher realized hedge losses, lower earnings of \$70 million from the retail services business, largely due to unfavorable changes in unrealized positions on derivative contracts, lower solar earnings of \$40 million from lower generation and lower geothermal and natural gas earnings of \$7 million, partially offset by higher earnings at owned wind projects of \$88 million. Geothermal and natural gas earnings were lower due to higher geothermal operating and maintenance costs related to storms and outages as well as higher geothermal development costs, partially offset by favorable pricing and generation at the natural gas generating facilities. Earnings from owned wind projects were higher primarily due to favorable derivative contract valuations and from gains on the extinguishment of debt, partially offset by a decrease in operating revenue from lower generation.

HomeServices

Operating revenue increased \$32 million for 2024 compared to 2023, primarily due to higher mortgage revenue of \$35 million. The increase in mortgage revenue was due to a 4% increase in funded volume, primarily due to higher refinance activity, and a 7% increase in average loan size caused by low inventory driving an increase in average home sales prices.

Earnings decreased \$120 million for 2024 compared to 2023, primarily due to a charge of approximately \$140 million recognized in the first quarter of 2024 associated with a settlement reached in the ongoing real estate industry litigation matters, partially offset by higher mortgage earnings of \$31 million, mainly due to higher revenue, and favorable operating expenses, including lower compensation, marketing and occupancy costs.

Operating revenue decreased \$946 million for 2023 compared to 2022, primarily due to lower brokerage and settlement services revenue of \$873 million and lower mortgage revenue of \$68 million. The decrease in brokerage and settlement services revenue resulted from a 19% decrease in closed transaction volume due to rising interest rates and a corresponding decline in home sales. The lower mortgage revenue was due to a 28% decrease in funded volume, primarily due to rising interest rates.

Earnings decreased \$87 million for 2023 compared to 2022, primarily due to lower earnings from brokerage and settlement services of \$78 million and mortgage services of \$10 million. Earnings declined due to declines in closed brokerage transaction volume and mortgage funded volume, partially offset by favorable operating expenses primarily due to lower compensation costs.

BHE and Other

Earnings decreased \$102 million for 2024 compared to 2023, primarily due to the \$154 million unfavorable comparative change and lower net interest and dividend income of \$18 million each related to the Company's investment in BYD, partially offset by \$34 million of lower dividends due to the final redemption of BHE's 4.00% Perpetual Preferred Stock issued to certain subsidiaries of Berkshire Hathaway in December 2023 and favorable consolidated income tax adjustments totaling \$28 million.

Earnings increased \$2,094 million for 2023 compared to 2022, primarily due to the \$2,045 million favorable comparative change related to the Company's investment in BYD, favorable changes in the cash surrender value of corporate-owned life insurance policies of \$45 million and \$12 million of lower dividends on BHE's 4.00% Perpetual Preferred Stock issued to certain subsidiaries of Berkshire Hathaway. These items were partially offset by unfavorable consolidated income tax adjustments, largely state related, totaling \$48 million and higher BHE corporate interest expense of \$52 million from an April 2022 debt issuance.

Liquidity and Capital Resources

Each of BHE's direct and indirect subsidiaries is organized as a legal entity separate and apart from BHE and its other subsidiaries. It should not be assumed that the assets of any subsidiary will be available to satisfy BHE's obligations or the obligations of its other subsidiaries. However, unrestricted cash or other assets that are available for distribution may, subject to applicable law, regulatory commitments and the terms of financing and ring-fencing arrangements for such parties, be advanced, loaned, paid as dividends or otherwise distributed or contributed to BHE or affiliates thereof. The Company's long-term debt may include provisions that allow BHE or its subsidiaries to redeem such debt in whole or in part at any time. These provisions generally include make-whole premiums. Refer to Note 18 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for further discussion regarding the limitation of distributions from BHE's subsidiaries.

As of December 31, 2024, the Company's total net liquidity was as follows (in millions):

	BHE	PacifiCorp	MidAmerican Funding	NV Energy	Northern Powergrid	BHE Canada	HomeServices	BHE Pipeline Group and Other	Total
Cash and cash equivalents	\$ 78	\$ 46	\$ 552	\$ 47	\$ 48	\$ 78	\$ 311	\$ 232	\$ 1,392
Credit facilities ⁽¹⁾	3,500	2,900	1,509	1,000	344	643	1,700	—	11,596
Less:									
Short-term debt	(180)	(240)	—	—	(94)	(106)	(503)	—	(1,123)
Tax-exempt bond support and letters of credit	—	(52)	(271)	—	—	(2)	—	—	(325)
Net credit facilities	3,320	2,608	1,238	1,000	250	535	1,197	—	10,148
Total net liquidity	\$3,398	\$ 2,654	\$ 1,790	\$1,047	\$ 298	\$ 613	\$ 1,508	\$ 232	\$11,540
Credit facilities:									
Maturity dates	2027	2025, 2027	2025, 2027	2027	2026	2027, 2029	2025, 2026		

(1) Includes \$94 million drawn on capital expenditure and other uncommitted credit facilities at Northern Powergrid.

Refer to Note 9 of the Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for further discussion regarding the Company's credit facilities, letters of credit, equity commitments and other related items.

Operating Activities

Net cash flows from operating activities for the years ended December 31, 2024 and 2023 were \$8.4 billion and \$7.1 billion, respectively. The increase was primarily due to favorable operating results, changes in working capital, including receipt of \$401 million of insurance reimbursements related to wildfire liabilities, and higher income tax receipts, partially offset by an increase in wildfire liability settlement payments and higher cash paid for interest.

Net cash flows from operating activities for the years ended December 31, 2023 and 2022 were \$7.1 billion and \$9.4 billion, respectively. The decrease was primarily due to unfavorable operating results, the timing of payments related to fuel and energy costs, a decrease in income tax receipts and changes in working capital.

The timing of the Company's income tax cash flows from period to period can be significantly affected by the estimated federal income tax payment methods selected and assumptions made for each payment date.

Investing Activities

Net cash flows from investing activities for the years ended December 31, 2024 and 2023 were \$(6.0) billion and \$(5.9) billion, respectively. The change was primarily due to lower proceeds from sales and maturities, net of purchases, of U.S. Treasury Bills totaling \$349 million, partially offset by higher capital expenditures of \$135 million and higher proceeds from sales, net of purchases, of marketable securities of \$55 million. Refer to "Future Uses of Cash" for further discussion of capital expenditures.

Net cash flows from investing activities for the years ended December 31, 2023 and 2022 were \$(5.9) billion and \$(7.8) billion, respectively. The change was primarily due to higher proceeds from sales and maturities, net of purchases, of U.S. Treasury Bills totaling \$3.0 billion, higher proceeds from sales, net of purchases, of marketable securities of \$316 million and lower cash paid for acquisitions, partially offset by higher capital expenditures of \$(1.6) billion. Refer to "Future Uses of Cash" for further discussion of capital expenditures.

Financing Activities

Net cash flows from financing activities for the year ended December 31, 2024 were \$(2.6) billion. Sources of cash totaled \$6.4 billion and consisted of proceeds from subsidiary debt issuances. Uses of cash totaled \$9.0 billion and consisted of net repayments of short-term debt totaling \$3.0 billion, repayments of subsidiary debt totaling \$2.8 billion, repurchases of common stock of 2.3 billion, repayment of notes payable of \$600 million and distributions to noncontrolling interests of \$163 million.

Net cash flows from financing activities for the year ended December 31, 2023 were \$(1.3) billion. Sources of cash totaled \$7.1 billion and consisted of proceeds from subsidiary debt issuances of \$4.1 billion and net proceeds from short-term debt totaling \$3.0 billion. Uses of cash totaled \$8.4 billion and consisted mainly of \$3.3 billion for the purchase of Cove Point noncontrolling interest, repayments of subsidiary debt totaling \$2.8 billion, repayments of BHE senior debt of \$900 million, preferred stock redemptions totaling \$850 million and distributions to noncontrolling interests of \$395 million.

Net cash flows from financing activities for the year ended December 31, 2022 were \$(1.0) billion. Sources of cash totaled \$3.9 billion and consisted of proceeds from subsidiary debt issuances of \$2.9 billion and proceeds from BHE senior debt issuances of \$986 million. Uses of cash totaled \$4.9 billion and consisted mainly of repayments of subsidiary debt totaling \$1.5 billion, repurchases of common stock of \$870 million, net repayments of short-term debt totaling \$867 million, preferred stock redemptions totaling \$800 million and distributions to noncontrolling interests of \$524 million.

Recent Financing Transactions

In January and February 2025, the Company issued \$1.5 billion of term debt with a weighted average interest rate of 6.0% and maturity dates ranging from 2035 to 2055.

Debt Repurchases

The Company may from time to time seek to acquire its outstanding debt securities through cash purchases in the open market, privately negotiated transactions or otherwise. Any debt securities repurchased by the Company may be reissued or resold by the Company from time to time and will depend on prevailing market conditions, the Company's liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

Preferred Stock Redemptions

For the years ended December 31, 2023 and 2022, BHE redeemed at par 849,982 and 800,006 shares of its 4.00% Perpetual Preferred Stock from certain subsidiaries of Berkshire Hathaway Inc. for \$850 million and \$800 million.

Common Stock Transactions

For the year ended December 31, 2024, BHE repurchased 4,424,494 shares of its voting common stock held by certain family members and related or affiliated entities of the late Mr. Walter Scott, Jr., a former member of BHE's Board of Directors for (i) cash in an aggregate amount of \$2.4 billion and (ii) a Promissory Note, due and payable on September 30, 2025, having an aggregate principal amount of \$600 million, which was fully repaid plus accrued interest in October 2024.

For the year ended December 31, 2022, BHE repurchased 740,961 shares of its voting common stock held by Mr. Gregory E. Abel, BHE's Chair, for \$870 million. The purchase was pursuant to the terms of BHE's Shareholders Agreement.

There were no common stock repurchases for the year ended December 31, 2023.

Future Uses of Cash

The Company has available a variety of sources of liquidity and capital resources, both internal and external, including net cash flows from operating activities, public and private debt offerings, the issuance of commercial paper, the use of unsecured revolving credit facilities, the issuance of equity and other sources. These sources are expected to provide funds required for current operations, capital expenditures, acquisitions, investments, debt retirements and other capital requirements. The availability and terms under which BHE and each subsidiary has access to external financing depends on a variety of factors, including regulatory approvals, its credit ratings, investors' judgment of risk and conditions in the overall capital markets, including the condition of the utility industry and project finance markets, among other items.

Capital Expenditures

The Company has significant future capital requirements. Capital expenditure needs are reviewed regularly by management and may change significantly as a result of these reviews, which may consider, among other factors, impacts to customers' rates; changes in environmental and other rules and regulations; outcomes of regulatory proceedings; changes in income tax laws; general business conditions; load projections; system reliability standards; the cost and efficiency of construction labor, equipment and materials; commodity prices; and the cost and availability of capital. Expenditures for certain assets may ultimately include acquisitions of existing assets.

The Company's historical and forecast capital expenditures, each of which exclude amounts for non-cash equity AFUDC and other non-cash items, by reportable segment for the years ended December 31 are as follows (in millions):

	Historical			Forecast		
	2022	2023	2024	2025	2026	2027
PacifiCorp	\$ 2,166	\$ 3,226	\$ 3,102	\$ 2,926	\$ 2,604	\$ 3,119
MidAmerican Funding	1,869	1,833	1,704	1,843	2,290	3,014
NV Energy	1,113	1,797	1,777	2,251	2,960	2,913
Northern Powergrid	768	557	657	812	805	819
BHE Pipeline Group	1,157	1,294	1,050	1,450	1,091	1,307
BHE Transmission	200	206	253	361	406	304
BHE Renewables	140	177	455	534	306	192
HomeServices	48	41	8	21	23	26
BHE and Other ⁽¹⁾	44	17	7	—	8	2
Total	<u>\$ 7,505</u>	<u>\$ 9,148</u>	<u>\$ 9,013</u>	<u>\$ 10,198</u>	<u>\$ 10,493</u>	<u>\$ 11,696</u>

(1) BHE and Other includes intersegment eliminations.

	Historical			Forecast		
	2022	2023	2024	2025	2026	2027
Electric transmission	\$ 1,693	\$ 1,802	\$ 1,679	\$ 2,196	\$ 2,471	\$ 2,867
Electric distribution	1,650	2,047	2,235	2,421	2,529	2,415
Wind generation	774	1,538	937	967	970	1,180
Natural gas transmission and storage	945	997	854	1,042	975	1,211
Electric battery storage	8	367	180	505	126	16
Solar generation	422	271	324	307	767	927
Wildfire mitigation	188	352	622	654	766	797
Other	1,825	1,774	2,182	2,106	1,889	2,283
Total	<u>\$ 7,505</u>	<u>\$ 9,148</u>	<u>\$ 9,013</u>	<u>\$ 10,198</u>	<u>\$ 10,493</u>	<u>\$ 11,696</u>

The Company's historical and forecast capital expenditures consisted mainly of the following:

- Electric transmission includes both growth and operating expenditures. Growth expenditures include spending for the following:
 - PacifiCorp's transmission investment primarily reflects costs associated with major transmission projects. Expenditures for certain projects placed in-service during 2024 totaled \$382 million for 2024, \$738 million for 2023 and \$921 million for 2022. Planned spending for major transmission projects that are expected to be placed in-service through 2034 totals \$336 million in 2025, \$262 million in 2026 and \$342 million in 2027.
 - Nevada Utilities' Greenlink Nevada transmission expansion program totaling \$265 million for 2024, \$130 million for 2023 and \$33 million for 2022. Planned spending for the expansion program estimated to be placed in-service in 2027 through 2028 totals \$764 million in 2025, \$1.2 billion in 2026 and \$1.1 billion in 2027.

- Operating expenditures include spending for system reinforcement, upgrades and replacements of facilities to maintain system reliability and investments in routine expenditures for transmission needed to serve existing and expected demand.
- Electric distribution includes both growth and operating expenditures. Growth expenditures include spending for new customer connections and enhancements to existing customer connections. Operating expenditures include spending for ongoing distribution systems infrastructure needed at the Utilities and Northern Powergrid, storm damage restoration and repairs and investments in routine expenditures for distribution needed to serve existing and expected demand.
- Wind generation includes both growth and operating expenditures. Growth expenditures include spending for the following:
 - Construction of wind-powered generating facilities at MidAmerican Energy totaling \$127 million for 2024, \$608 million for 2023 and \$72 million for 2022. MidAmerican Energy placed in-service 200 MWs of new wind-powered generation in 2023. Planned spending for the construction of additional wind-powered generating facilities totals \$272 million in 2025, \$182 million in 2026 and \$432 million in 2027.
 - Repowering of wind-powered generating facilities at MidAmerican Energy totaling \$307 million for 2024, \$47 million for 2023 and \$500 million for 2022. Planned spending for repowering totals \$444 million in 2025, \$697 million in 2026 and \$652 million in 2027. MidAmerican Energy expects its repowered facilities to meet IRS guidelines for the re-establishment of PTCs under the prevailing wage and apprenticeship guidelines for 10 years from the date the facilities are placed in-service.
 - Construction of new wind-powered generating facilities and construction at existing wind-powered generating facility sites acquired from third parties at PacifiCorp totaling \$396 million for 2024, \$735 million for 2023 and \$23 million for 2022. PacifiCorp placed in-service 50 MWs at the Rock River I and 61 MWs at the Rock Creek I wind-powered generating facility in 2024 and 42 MWs at the Foote Creek III and Foote Creek IV wind-powered generating facilities in 2023. Planned spending for the construction of additional wind-powered generating facilities and those at acquired sites totals \$162 million in 2025 and is primarily for the Rock Creek I and Rock Creek II wind-powered generating facilities totaling approximately 529 MWs that are expected to be placed in-service in 2025.
 - Repowering of wind-powered generating facilities at BHE Renewables totaling \$5 million for 2024, \$39 million for 2023 and \$45 million in 2022. BHE Renewables repowered facilities were placed in-service in the first quarter of 2024 and the fourth quarter of 2023 and meet IRS guidelines for the re-establishment of PTCs for 10 years.
- Natural gas transmission and storage includes both growth and operating expenditures. Growth expenditures include, among other items, spending for customer driven expansion projects. Operating expenditures include spending for pipeline integrity projects, automation and controls upgrades, corrosion control, unit exchanges, compressor modifications, projects related to Pipeline and Hazardous Materials Safety Administration natural gas storage rules and natural gas transmission, storage, LNG terminalling infrastructure needs to serve existing and expected demand and asset modernization programs.
- Electric battery storage includes growth expenditures, including spending for the following:
 - Construction at the Nevada Utilities of a 100-MW battery energy storage system co-located with a 150-MW solar photovoltaic facility that was developed in Clark County, Nevada which commenced commercial operation in May 2024, a 220-MW grid-tied battery energy storage system that was developed on the site of the retired Reid Gardner generating station in Clark County, Nevada that commenced operations in December 2023 and a 400-MW battery energy storage system co-located with a 400-MW solar photovoltaic facility that is being developed in Churchill County, Nevada with ownership share approved by the PUCN of 10% Nevada Power and 90% Sierra Pacific of which commercial operation of the battery energy storage system is expected by mid-2026 with total spend of \$116 million in 2024, \$352 million in 2023 and \$8 million in 2022. Planned spending totals \$387 million in 2025, \$106 million in 2026 and \$12 million in 2027.
 - Construction at BHE Renewables of a 46-MW battery storage system co-located with a 48-MW solar photovoltaic facility that will be developed in Kern County, California, with commercial operation expected in 2025 and a 50-MW battery storage system co-located with a 106-MW solar photovoltaic facility located in Jackson County, West Virginia, with commercial operation being completed in three phases between 2025 and 2027 with total spend of \$59 million in 2024. Planned spending totals \$53 million in 2025, \$20 million in 2026 and \$4 million in 2027.

- Solar generation includes growth expenditures, including spending for the following:
 - Construction and operation of solar-powered generating facilities at MidAmerican Energy including 141 MWs of small- and utility-scale solar generation which was placed in-service in 2022, with total spend of \$3 million in 2024, \$13 million in 2023 and \$119 million in 2022. Planned spending for the construction and operation of additional solar-powered generating facilities totals \$14 million in 2025, \$152 million in 2026 and \$492 million in 2027.
 - Construction of solar-powered generating facilities at the Nevada Utilities including expenditures for a 150-MW solar photovoltaic facility with an additional 100-MWs of co-located battery storage developed in Clark County, Nevada which commenced commercial operation in May 2024 and a 400-MW solar photovoltaic facility with an additional 400-MW of co-located battery storage that is being developed in Churchill County, Nevada with ownership share approved by the PUCN of 10% Nevada Power and 90% Sierra Pacific of which commercial operation of the solar facility is expected by early 2027 with total spend of \$124 million in 2024, \$189 million in 2023 and \$121 million in 2022. Planned spending totals \$29 million in 2025, \$338 million in 2026 and \$350 million in 2027.
 - Construction of solar-powered generating facilities at BHE Renewables including expenditures for a 48-MW solar photovoltaic facility with an additional 46-MWs of co-located battery storage that will be developed in Kern County, California, with commercial operation expected in 2025 and a 106-MW solar photovoltaic facility with an additional 50-MWs of co-located battery storage located in Jackson County, West Virginia, with commercial operation being completed in three phases between 2025 and 2027 with total spend of \$153 million for 2024, \$60 million for 2023 and \$22 million for 2022. Planned spending totals \$119 million in 2025, \$47 million in 2026 and 7 million in 2027.
- Wildfire mitigation includes operating expenditures, including spending for the following:
 - Expenditures at PacifiCorp totaling \$539 million in 2024, \$325 million in 2023 and \$159 million in 2022. Planned spending totals \$532 million in 2025, \$623 million in 2026 and \$669 million in 2027 and is comprised of reducing wildfire risk in the FHCA by conversion of overhead systems to underground, replacing overhead bare wire conductor with covered conductors and deployment of advanced protection devices for faster fault detection. The efforts will also include an expansion of the weather station network and predictive tools for situational awareness across the entire service territory.
 - Expenditures at the Nevada Utilities totaling \$35 million in 2024, \$20 million in 2023 and \$20 million in 2022. Planned spending totals \$57 million in 2025, \$79 million in 2026 and \$55 million in 2027 is comprised of reducing wildfire risk in Tier 3 HTAs by rebuilding distribution lines with covered conductor, converting overhead distribution lines to underground and copper wire and pole replacement projects.
- Other capital expenditures includes both growth and operating expenditures, including spending for routine expenditures for generation and other infrastructure needed to serve existing and expected demand, natural gas distribution, technology, and environmental spending relating to emissions control equipment and the management of CCR.

Off-Balance Sheet Arrangements

The Company has certain investments that are accounted for under the equity method in accordance with GAAP. Accordingly, an amount is recorded on the Company's Consolidated Balance Sheets as an equity investment and is increased or decreased for the Company's pro-rata share of earnings or losses, respectively, less any dividends from such investments. Certain equity investments are presented on the Consolidated Balance Sheets net of investment tax credits.

As of December 31, 2024, the Company's investments that are accounted for under the equity method had short- and long-term debt of \$2.8 billion, unused revolving credit facilities of \$151 million and letters of credit outstanding of \$88 million. As of December 31, 2024, the Company's pro-rata share of such short- and long-term debt was \$1.3 billion, unused revolving credit facilities was \$76 million and outstanding letters of credit was \$43 million. The entire amount of the Company's pro-rata share of the outstanding short- and long-term debt and unused revolving credit facilities is non-recourse to the Company. The entire amount of the Company's pro-rata share of the outstanding letters of credit is recourse to the Company. Although the Company is generally not required to support debt service obligations of its equity investees, default with respect to this non-recourse short- and long-term debt could result in a loss of invested equity.

Material Cash Requirements

The Company has cash requirements that may affect its consolidated financial condition that arise primarily from long- and short-term debt (refer to Note 9, 10 and 11), operating and financing leases (refer to Note 6), firm commitments (refer to Note 16), letters of credit (refer to Note 9), construction and other development costs (refer to Liquidity and Capital Resources included within this Item 7), uncertain tax positions (refer to Note 12) and AROs (refer to Note 14). Refer, where applicable, to the respective referenced note in Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

The Company has cash requirements relating to interest payments of \$44.2 billion on long-term debt, including \$2.5 billion due in 2025.

Regulatory Matters

The Company is subject to comprehensive regulation. Refer to the discussion contained in Item 1 of this Form 10-K for further information regarding the Company's general regulatory framework and current regulatory matters.

Environmental Laws and Regulations

The Company is subject to federal, state, local and foreign laws and regulations regarding air quality, climate change, emissions performance standards, water quality, coal ash disposal and other environmental matters that have the potential to impact its current and future operations. In addition to imposing continuing compliance obligations, these laws and regulations provide regulators with the authority to levy substantial penalties for noncompliance, including fines, injunctive relief and other sanctions. These laws and regulations are administered by various federal, state, local and international agencies. The Company believes it is in material compliance with all applicable laws and regulations, although many are subject to interpretation that may ultimately be resolved by the courts. Environmental laws and regulations continue to evolve, and the Company is unable to predict the impact of the changing laws and regulations on its operations and financial results.

Refer to "Environmental Laws and Regulations" in Item 1 of this Form 10-K for further discussion regarding environmental laws and regulations.

Collateral and Contingent Features

Debt of BHE and debt and preferred securities of certain of its subsidiaries are rated by credit rating agencies. Assigned credit ratings are based on each rating agency's assessment of the rated company's ability to, in general, meet the obligations of its issued debt or preferred securities. The credit ratings are not a recommendation to buy, sell or hold securities, and there is no assurance that a particular credit rating will continue for any given period of time.

BHE and its subsidiaries have no credit rating downgrade triggers that would accelerate the maturity dates of outstanding debt, and a change in ratings is not an event of default under the applicable debt instruments. The Company's unsecured revolving credit facilities do not require the maintenance of a minimum credit rating level in order to draw upon their availability. However, commitment fees and interest rates under the credit facilities are tied to credit ratings and increase or decrease when the ratings change. A ratings downgrade could also increase the future cost of commercial paper, short- and long-term debt issuances or new credit facilities.

In accordance with industry practice, certain wholesale agreements, including derivative contracts, contain credit support provisions that in part base certain collateral requirements on credit ratings for senior unsecured debt as reported by one or more of the recognized credit rating agencies. These agreements may either specifically provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed specified rating-dependent threshold levels ("credit-risk-related contingent features") or provide the right for counterparties to demand "adequate assurance," or in some cases terminate the contract, in the event of a material adverse change in creditworthiness. These rights can vary by contract and by counterparty. As of December 31, 2024, the applicable entities' credit ratings from the recognized credit rating agencies were investment grade. If all credit-risk-related contingent features or adequate assurance provisions for these agreements had been triggered as of December 31, 2024, the Company would have been required to post \$423 million of additional collateral. The Company's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation, or other factors.

Inflation

Historically, overall inflation and changing prices in the economies where BHE's subsidiaries operate have not had a significant impact on the Company's consolidated financial results. In the U.S. and Canada, the Regulated Businesses operate under cost-of-service based rate-setting structures administered by various state and provincial commissions and the FERC. Under these rate-setting structures, the Regulated Businesses are allowed to include prudent costs in their rates, including the impact of inflation. The price control formula used by the Northern Powergrid Distribution Companies incorporates the rate of inflation in determining rates charged to customers. BHE's subsidiaries attempt to minimize the potential impact of inflation on their operations through the use of fuel, energy and other cost adjustment clauses and bill riders, by employing prudent risk management and hedging strategies and by considering, among other areas, its impact on purchases of energy, operating expenses, materials and equipment costs, contract negotiations, future capital spending programs and long-term debt issuances. There can be no assurance that such actions will be successful.

New Accounting Pronouncements

For a discussion of new accounting pronouncements affecting the Company, refer to Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Critical Accounting Estimates

Certain accounting measurements require management to make estimates and judgments concerning transactions that will be settled several years in the future. Amounts recognized on the Consolidated Financial Statements based on such estimates involve numerous assumptions subject to varying and potentially significant degrees of judgment and uncertainty and will likely change in the future as additional information becomes available. The following critical accounting estimates are impacted significantly by the Company's methods, judgments and assumptions used in the preparation of the Consolidated Financial Statements and should be read in conjunction with the Company's Summary of Significant Accounting Policies included in Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Accounting for the Effects of Certain Types of Regulation

The Regulated Businesses prepare their financial statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, the Regulated Businesses defer the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in regulated rates occur.

The Company continually evaluates the applicability of the guidance for regulated operations and whether its regulatory assets and liabilities are probable of inclusion in future regulated rates by considering factors such as a change in the regulator's approach to setting rates from cost-based ratemaking to another form of regulation, other regulatory actions or the impact of competition that could limit the Regulated Businesses' ability to recover their costs. The Company believes its application of the guidance for regulated operations is appropriate and its existing regulatory assets and liabilities are probable of inclusion in future regulated rates. The evaluation reflects the current political and regulatory climate at the federal, state and provincial levels. If it becomes no longer probable that the deferred costs or income will be included in future regulated rates, the related regulatory assets and liabilities will be recognized in net income, returned to customers or re-established as AOCI. Total regulatory assets were \$5.3 billion and total regulatory liabilities were \$7.0 billion as of December 31, 2024. Refer to Note 7 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding the Regulated Businesses' regulatory assets and liabilities.

Impairment of Goodwill and Long-Lived Assets

The Company's Consolidated Balance Sheet as of December 31, 2024 includes goodwill of acquired businesses of \$11.4 billion. The Company evaluates goodwill for impairment at least annually and completed its annual review as of October 31, 2024. Additionally, no indicators of impairment were identified as of December 31, 2024. Significant judgment is required in estimating the fair value of the reporting unit and performing goodwill impairment tests. The Company uses a variety of methods to estimate a reporting unit's fair value, principally discounted projected future net cash flows. Key assumptions used include, but are not limited to, the use of estimated future cash flows; multiples of earnings or rate base; and an appropriate discount rate. Estimated future cash flows are impacted by, among other factors, growth rates, changes in regulations and rates, ability to renew contracts and estimates of future commodity prices. In estimating future cash flows, the Company incorporates current market information, as well as historical factors.

The Company evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or when the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value and any resulting impairment loss is reflected on the Consolidated Statements of Operations. As a majority of all property, plant and equipment is used in regulated businesses, the impacts of regulation are considered when evaluating the carrying value of regulated assets.

The estimate of cash flows arising from the future use of an asset, for the purposes of impairment analysis, requires the exercise of judgment. Circumstances that could significantly alter the calculation of fair value or the recoverable amount of an asset may include significant changes in the regulatory environment, the business climate, management's plans, legal factors, market price of the asset, the use of the asset, the physical condition of the asset, future market prices, load growth, competition and many other factors over the life of the asset. Any resulting impairment loss is highly dependent on the underlying assumptions and could significantly affect the Company's results of operations.

Pension and Other Postretirement Benefits

Certain of the Company's subsidiaries sponsor defined benefit pension and other postretirement benefit plans that cover the majority of employees. The Company recognizes the funded status of the defined benefit pension and other postretirement benefit plans on the Consolidated Balance Sheets. Funded status is the fair value of plan assets minus the benefit obligation as of the measurement date. As of December 31, 2024, the Company recognized a net asset totaling \$425 million for the funded status of the defined benefit pension and other postretirement benefit plans. As of December 31, 2024, amounts not yet recognized as a component of net periodic benefit cost that were included in net regulatory assets totaled \$173 million and in AOCI totaled \$565 million.

The expense and benefit obligations relating to these defined benefit pension and other postretirement benefit plans are based on actuarial valuations. Inherent in these valuations are key assumptions, including, but not limited to, discount rates, expected long-term rate of return on plan assets and healthcare cost trend rates. These key assumptions are reviewed annually and modified as appropriate. The Company believes that the key assumptions utilized in recording obligations under the plans are reasonable based on prior plan experience and current market and economic conditions. Refer to Note 13 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for disclosures about the defined benefit pension and other postretirement benefit plans, including the key assumptions used to calculate the funded status and net periodic benefit cost for these plans as of and for the year ended December 31, 2024.

The Company chooses a discount rate based upon high quality debt security investment yields in effect as of the measurement date that corresponds to the expected benefit period. The pension and other postretirement benefit liabilities increase as the discount rate is reduced.

In establishing its assumption as to the expected long-term rate of return on plan assets, the Company utilizes the expected asset allocation and return assumptions for each asset class based on historical performance and forward-looking views of the financial markets. Pension and other postretirement benefits expense increases as the expected long-term rate of return on plan assets decreases. The Company regularly reviews its actual asset allocations and rebalances its investments to its targeted allocations when considered appropriate.

The Company chooses a healthcare cost trend rate that reflects the near and long-term expectations of increases in medical costs and corresponds to the expected benefit payment periods. The healthcare cost trend rate is assumed to gradually decline to 5.00% by 2033, at which point the rate of increase is assumed to remain constant.

The key assumptions used may differ materially from period to period due to changing market and economic conditions. These differences may result in a significant impact to pension and other postretirement benefits expense and funded status. If changes were to occur for the following key assumptions, the approximate effect on the Consolidated Financial Statements would be as follows (dollars in millions):

	Domestic Plans				United Kingdom	
	Pension Plans		Other Postretirement Benefit Plans		Pension Plan	
	+0.5%	-0.5%	+0.5%	-0.5%	+0.5%	-0.5%
Effect on December 31, 2024						
Benefit Obligations:						
Discount rate	\$ (71)	\$ 76	\$ (17)	\$ 19	\$ (61)	\$ 66
Effect on 2024 Periodic Cost:						
Discount rate	\$ 3	\$ —	\$ —	\$ (1)	\$ (4)	\$ 2
Expected rate of return on plan assets	(10)	10	(3)	3	(6)	6

A variety of factors affect the funded status of the plans, including discount rates, asset returns, mortality assumptions, plan changes and the Company's funding policy for each plan.

Income Taxes

In determining the Company's income taxes, management is required to interpret complex income tax laws and regulations, which includes consideration of regulatory implications imposed by the Company's various regulatory commissions. The Company's income tax returns are subject to continuous examinations by federal, state, local and foreign income tax authorities that may give rise to different interpretations of these complex laws and regulations. Due to the nature of the examination process, it generally takes years before these examinations are completed and these matters are resolved. The Company recognizes the tax benefit from an uncertain tax position only if it is more-likely-than-not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the Consolidated Financial Statements from such a position are measured based on the largest benefit that is more-likely-than-not to be realized upon ultimate settlement. Although the ultimate resolution of the Company's federal, state, local and foreign income tax examinations is uncertain, the Company believes it has made adequate provisions for these income tax positions. The aggregate amount of any additional income tax liabilities that may result from these examinations is not expected to have a material impact on the Company's consolidated financial results. Refer to Note 12 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding the Company's income taxes.

It is probable the Company's regulated businesses will pass income tax benefit and expense related to the federal tax rate change from 35% to 21%, certain property-related basis differences and other various differences on to their customers. As of December 31, 2024, these amounts were recognized as a net regulatory liability of \$2.0 billion and will be included in regulated rates when the temporary differences reverse.

The Company has not established deferred income taxes on its undistributed foreign earnings that have been determined by management to be reinvested indefinitely; however, the Company periodically evaluates its capital requirements. If circumstances change in the future and a portion of the Company's undistributed foreign earnings were repatriated, the dividends may be subject to taxation in the U.S. but the tax is not expected to be material.

Loss Contingencies

As a result of certain conditions, situations or circumstances involving uncertainty as to possible loss, including (i) several wildfires that have occurred in the Company's service territory and surrounding areas in the western U.S. and Canada and (ii) antitrust cases at HomeServices, the Company is required to evaluate its exposure to potential loss contingencies arising from claims associated with these items. In determining this exposure, the Company is required to assess whether the likelihood of loss for each of these items is remote, reasonably possible or probable, which involves complex judgments based on several variables including available information regarding the outcome of the appeals process, cause and origin of the wildfires, investigations, discovery associated with lawsuits and negotiations with various parties. If deemed reasonably possible, the Company is required to estimate the potential loss or range of potential loss and disclose any material amounts. If deemed probable, the Company is required to accrue a loss if reasonably estimable based on the bottom end of the range if no amount within the range of estimated loss is any better than another amount. Many assumptions and variables are involved in determining the estimates relative to wildfires, including identifying the various categories of potential loss such as fire suppression costs, real and personal property damages, natural resource damages for certain areas and noneconomic damages such as personal injury damages and loss of life damages. Within the categories of potential loss, further assumptions are made regarding items such as the types of structures damaged, estimated replacement values associated with those structures, value of personal property, the types of natural resource damage such as timber, the value of that timber, the nature of noneconomic damages such as those arising from personal injuries, other damages the Company may be responsible for if found negligent such as punitive damages, and the amount of any penalties or fines that may be imposed by governmental entities. Refer to Note 16 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding the Company's loss contingencies associated with wildfires and the antitrust cases at HomeServices.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The Company's Consolidated Balance Sheets include assets and liabilities with fair values that are subject to market risks. The Company's significant market risks are primarily associated with commodity prices, interest rates, foreign currency exchange rates and the extension of credit to counterparties with which the Company transacts. The following discussion addresses the significant market risks associated with the Company's business activities. Each of the Company's businesses has established guidelines for credit risk management.

Commodity Price Risk

The Company is principally exposed to electricity, natural gas, coal and fuel oil commodity price risk primarily through BHE's ownership of the Utilities as they have an obligation to serve retail customer load in their regulated service territories. The Utilities' load and generating facilities represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel required to generate electricity, wholesale electricity that is purchased and sold and natural gas supply for retail customers. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather, market liquidity, generating facility availability, customer usage, storage and transmission and transportation constraints. The Company does not engage in a material amount of proprietary trading activities. To manage a portion of its commodity price risk, the Company uses commodity derivative contracts, which may include forwards, futures, options, swaps and other agreements, to effectively secure future supply or sell future production generally at fixed prices. The Company does not hedge all of its commodity price risk, thereby exposing the unhedged portion to changes in market prices. The Company's exposure to commodity price risk is generally limited by its ability to include commodity costs in regulated rates, which is subject to regulatory lag that occurs between the time the costs are incurred and when the costs are included in regulated rates, as well as the impact of any customer sharing resulting from cost adjustment mechanisms.

The table that follows summarizes the Company's price risk on commodity contracts accounted for as derivatives, excluding collateral netting of \$9 million and \$23 million, respectively, as of December 31, 2024 and 2023, and shows the effects of a hypothetical 10% increase and 10% decrease in forward market prices with the contracted or expected volumes. The selected hypothetical change does not reflect what could be considered the best or worst case scenarios (dollars in millions).

	Fair Value - Net Asset (Liability)	Estimated Fair Value after Hypothetical Change in Price	
		10% increase	10% decrease
As of December 31, 2024:			
Not designated as hedging contracts	\$ (168)	\$ (118)	\$ (218)
Designated as hedging contracts	21	23	19
Total commodity derivative contracts	<u>\$ (147)</u>	<u>\$ (95)</u>	<u>\$ (199)</u>
As of December 31, 2023:			
Not designated as hedging contracts	\$ (121)	\$ (14)	\$ (228)
Designated as hedging contracts	11	19	3
Total commodity derivative contracts	<u>\$ (110)</u>	<u>\$ 5</u>	<u>\$ (225)</u>

The settled cost of certain of the Company's commodity derivative contracts not designated as hedging contracts is included in regulated rates and, therefore, net unrealized gains and losses associated with interim price movements on commodity derivative contracts do not expose the Company to earnings volatility. Consolidated financial results would be negatively impacted if the costs of wholesale electricity, wholesale natural gas or fuel are higher than what is included in regulated rates, including the impacts of adjustment mechanisms. As of December 31, 2024 and 2023, a net regulatory asset of \$181 million and \$166 million, respectively, was recorded related to the net derivative liability of \$168 million and \$121 million, respectively. For the Company's commodity derivative contracts designated as hedging contracts, net unrealized gains and losses associated with interim price movements on commodity derivative contracts, to the extent the hedge is considered effective, generally do not expose the Company to earnings volatility.

Interest Rate Risk

The Company is exposed to interest rate risk on its outstanding variable-rate short- and long-term debt, future debt issuances and mortgage commitments. The Company manages its interest rate risk by limiting its exposure to variable interest rates primarily through the issuance of fixed-rate long-term debt and by monitoring market changes in interest rates. As a result of the fixed interest rates, the Company's fixed-rate long-term debt does not expose the Company to the risk of loss due to changes in market interest rates. Additionally, because fixed-rate long-term debt is not carried at fair value on the Consolidated Balance Sheets, changes in fair value would impact earnings and cash flows only if the Company were to reacquire all or a portion of these instruments prior to their maturity. The nature and amount of the Company's short- and long-term debt can be expected to vary from period to period as a result of future business requirements, market conditions and other factors. Refer to Notes 9, 10, 11, and 15 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional discussion of the Company's short and long-term debt.

As of December 31, 2024 and 2023, the Company had short- and long-term variable-rate obligations totaling \$1.5 billion and \$5.0 billion, respectively, that expose the Company to the risk of increased interest expense in the event of increases in short-term interest rates. If variable interest rates were to increase by 10% from December 31 levels, it would not have a material effect on the Company's consolidated annual interest expense. The carrying value of the variable-rate obligations approximates fair value as of December 31, 2024 and 2023.

The Company may from time to time enter into interest rate derivative contracts, such as interest rate swaps or locks, forward sale commitments or mortgage interest rate lock commitments, to mitigate the Company's exposure to interest rate risk. Changes in fair value of agreements designated as cash flow hedges are reported in AOCI to the extent the hedge is effective until the forecasted transaction occurs. Changes in fair value of agreements not designated as hedging contracts are recognized in earnings. As of December 31, 2024 and 2023, the Company had variable-to-fixed interest rate swaps with notional amounts of \$370 million and \$426 million, respectively, £137 million and £163 million, respectively, and A\$154 million and A\$161 million, respectively, to protect the Company against an increase in interest rates. Additionally, as of December 31, 2024 and 2023, the Company had mortgage commitments, net, with notional amounts of \$1.2 billion and \$406 million, respectively, to protect the Company against an increase in interest rates. The fair value of the Company's interest rate derivative contracts was a net derivative asset of \$79 million and \$78 million as of December 31, 2024 and 2023, respectively. A hypothetical 10 basis point increase and a 10 basis point decrease in interest rates would not have a material impact on the Company.

The Company holds foreign currency swaps with the purpose of hedging the foreign currency exchange rate associated with Euro denominated debt. As of December 31, 2024 and 2023, the Company had €250 million in aggregate notional amounts of these foreign currency swaps outstanding. A hypothetical 10% decrease in market interest rates would not have resulted in a material decrease in fair value of the Company's foreign currency swaps.

Foreign Currency Exchange Rate Risk

BHE's business operations and investments outside of the U.S. increase its risk related to fluctuations in foreign currency exchange rates primarily in relation to the British pound and the Canadian dollar. BHE's reporting currency is the U.S. dollar, and the value of the assets and liabilities, earnings, cash flows and potential distributions from BHE's foreign operations changes with the fluctuations of the currency in which they transact.

Northern Powergrid's functional currency is the British pound. As of December 31, 2024, a 10% devaluation in the British pound to the U.S. dollar would result in the Company's Consolidated Balance Sheet being negatively impacted by a \$523 million cumulative translation adjustment in AOCI. A 10% devaluation in the average currency exchange rate would have resulted in lower reported earnings for Northern Powergrid of \$55 million in 2024.

BHE Canada's functional currency is the Canadian dollar. As of December 31, 2024, a 10% devaluation in the Canadian dollar to the U.S. dollar would result in the Company's Consolidated Balance Sheet being negatively impacted by a \$538 million cumulative translation adjustment in AOCI. A 10% devaluation in the average currency exchange rate would have resulted in lower reported earnings for BHE Canada of \$19 million in 2024.

Credit Risk

Domestic Regulated Operations

The Utilities are exposed to counterparty credit risk associated with wholesale energy supply and marketing activities with other utilities, energy marketing companies, financial institutions and other market participants. Credit risk may be concentrated to the extent the Utilities' counterparties have similar economic, industry or other characteristics and due to direct or indirect relationships among the counterparties. Before entering into a transaction, the Utilities analyze the financial condition of each significant wholesale counterparty, establish limits on the amount of unsecured credit to be extended to each counterparty and evaluate the appropriateness of unsecured credit limits on an ongoing basis. To further mitigate wholesale counterparty credit risk, the Utilities enter into netting and collateral arrangements that may include margining and cross-product netting agreements and obtain third-party guarantees, letters of credit and cash deposits. If required, the Utilities exercise rights under these arrangements, including calling on the counterparty's credit support arrangement.

As of December 31, 2024, PacifiCorp's aggregate credit exposure with wholesale energy supply and marketing counterparties included counterparties having non-investment grade, internally rated credit ratings. Substantially all of these non-investment grade, internally rated counterparties are associated with long-duration solar and wind power purchase agreements, some of which are from facilities that have not yet achieved commercial operation and for which PacifiCorp has no obligation should the facilities not achieve commercial operation.

Substantially all of MidAmerican Energy's electric wholesale sales revenue results from participation in RTOs, including the MISO and the PJM. MidAmerican Energy's share of historical losses from defaults by other RTO market participants has not been material. Additionally, as of December 31, 2024, MidAmerican Energy's aggregate direct credit exposure from electric wholesale marketing counterparties was not material.

As of December 31, 2024, NV Energy's aggregate credit exposure from energy related transactions, based on settlement and mark-to-market exposures, net of collateral, was not material.

BHE GT&S primary customers include electric and natural gas distribution utilities and LNG export, import and storage customers. Northern Natural Gas' primary customers include utilities in the upper Midwest. Kern River's primary customers are electric and natural gas distribution utilities, major oil and natural gas companies or affiliates of such companies, electric generating companies, energy marketing and trading companies and financial institutions. As a general policy, collateral is not required for receivables from creditworthy customers. Customers' financial condition and creditworthiness, as defined by the tariff, are regularly evaluated and historical losses have been minimal. In order to provide protection against credit risk, and as permitted by the separate terms of each of BHE GT&S, Northern Natural Gas' and Kern River's tariffs, the companies have required customers that lack creditworthiness to provide cash deposits, letters of credit or other security until they meet the creditworthiness requirements of the respective tariff.

Northern Powergrid

The Northern Powergrid Distribution Companies charge fees for the use of their distribution systems to supply companies. The supply companies purchase electricity from generators and traders, sell the electricity to end-use customers and use the Northern Powergrid Distribution Companies' distribution networks pursuant to the multilateral "Distribution Connection and Use of System Agreement." The Northern Powergrid Distribution Companies' customers are concentrated in a small number of electricity supply businesses. During 2024, E.ON and certain of its affiliates and British Gas Trading Limited represented approximately 17% and 14%, respectively, of the total combined distribution revenue of the Northern Powergrid Distribution Companies. The industry operates in accordance with a framework which sets credit limits for each supply business based on its credit rating or payment history and requires them to provide credit cover if their value at risk (measured as being equivalent to 45 days usage) exceeds the credit limit. Acceptable credit typically is provided in the form of a parent company guarantee, letter of credit or an escrow account. Ofgem has indicated that, provided the Northern Powergrid Distribution Companies have implemented credit control, billing and collection in line with best practice guidelines and can demonstrate compliance with the guidelines or are able to satisfactorily explain departure from the guidelines, any bad debt losses arising from supplier default will be recovered through an increase in future allowed income. Losses incurred to date have not been material.

BHE Canada

AltaLink's primary source of operating revenue is the AESO, an entity rated AA- by Standard and Poor's. Because of the dependence on a single customer, any material failure of the customer to fulfill its obligations would significantly impair AltaLink's ability to meet its existing and future obligations. Total operating revenue for AltaLink was \$689 million for the year ended December 31, 2024.

BHE Renewables

BHE Renewables owns independent power projects that generally have separate project financing agreements. Operating revenue for these projects is derived primarily from long-term power purchase agreements with single customers, primarily utilities, which expire between 2024 and 2043. Because of the dependence generally from a single customer at each project, any material failure of the customer to fulfill its obligations would significantly impair that project's ability to meet its existing and future obligations. Total operating revenue for BHE Renewables' independent power projects was \$960 million for the year ended December 31, 2024.

Item 8. Financial Statements and Supplementary Data	
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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and the shareholders of
Berkshire Hathaway Energy Company
Des Moines, Iowa

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Berkshire Hathaway Energy Company and subsidiaries (the "Company") as of December 31, 2024 and 2023, the related consolidated statements of operations, comprehensive income, changes in equity, and cash flows for each of the three years in the period ended December 31, 2024, the related notes and the schedule listed in the Index at Item 15(a)(2) (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2024 and 2023, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2024, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements 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 financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the 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 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 financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current-period audit of the financial statements that were communicated or required to be communicated to the executive committee and that (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Regulatory Matters — Effects of Rate Regulation on the Financial Statements — Refer to Note 7 to the financial statements

Critical Audit Matter Description

The Company is subject to rate regulation by the Federal Energy Regulatory Commission as well as certain other regulatory commissions (collectively, the "Commissions"), which have jurisdiction with respect to the rates of electric and natural gas companies in the respective service territories where the Company operates. Management has determined its regulated operations meet the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the specialized rules to account for the effects of cost-based rate regulation. Accounting for the economic effects of rate regulation has a pervasive effect on the financial statements.

Regulated rates are subject to regulatory rate-setting processes. Rates are determined, approved, and established based on a cost-of-service basis, which is designed to allow the Company an opportunity to recover its prudently incurred costs of providing services and to earn a reasonable return on its invested capital. Regulatory decisions can have an effect on the recovery of costs, the rate of return earned on investment, and the timing and amount of assets to be recovered by rates. While the Company has indicated it expects to recover costs from customers through regulated rates, there is a risk that changes to the Commissions' approach to setting rates or other regulatory actions could limit the Company's ability to recover its costs.

We identified the effects of rate regulation on the financial statements as a critical audit matter due to the significant judgments made by management to support its assertions about certain affected account balances and disclosures and the high degree of subjectivity involved in assessing the impact of regulatory orders on the financial statements. Management judgments include assessing the likelihood of (1) recovery in future rates of incurred costs, (2) a disallowance of part of the cost of recently completed plant or plant under construction, and (3) refunds to customers. Given that management's accounting judgments are based on assumptions about the outcome of decisions by the Commissions, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate setting process due to its inherent complexities.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the uncertainty of decisions by the Commissions included the following, among others:

- We evaluated the Company's disclosures related to the effects of rate regulation, by testing certain recorded balances and evaluating regulatory developments.
- We read relevant regulatory orders issued by the Commissions, regulatory statutes, filings made by the Company and intervenors, and other external information. We evaluated relevant external information and compared it to certain recorded regulatory asset and liability balances for completeness.
- For certain regulatory matters, we inspected the Company's filings with the Commissions and the filings with the Commissions by intervenors to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedents of the Commissions' treatment of similar costs under similar circumstances.

Wildfires — Contingencies — Refer to Note 16 to the financial statements

Critical Audit Matter Description

As a result of several wildfires that have occurred in the Company's service territory and surrounding areas in Oregon and California, the Company is required to evaluate its exposure to potential loss contingencies arising from claims associated with the 2020 Wildfires and the 2022 McKinney Fire (the "Wildfires"). In determining this exposure, the Company is required to determine whether the likelihood of loss for each of the Wildfires is remote, reasonably possible or probable, which involves complex judgments based on several variables including available information regarding the cause and origin of the Wildfires, investigations, discovery associated with lawsuits and negotiations with claimants.

A provision for a loss contingency is recorded when it is probable that a liability has been incurred and the amount of loss can be reasonably estimated. If deemed reasonably possible, the Company is required to estimate and disclose the potential loss or range of potential loss.

Management has recorded estimated liabilities, which represent its best estimate of probable losses associated with the Wildfires.

We identified wildfire-related contingencies and the related disclosures as a critical audit matter because of the significant judgments made by management to determine the probability of loss and estimate the probable losses. Auditing the reasonableness of management's judgments, estimates and disclosures related to wildfire-related loss contingencies required the application of a high degree of judgment and extensive effort.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to management's judgments regarding the probability of loss, estimated losses, and related disclosures for wildfire-related contingencies included the following, among others:

- We evaluated management's judgments related to whether a loss was remote, reasonably possible, or probable for the Wildfires by inquiring of management and the Company's external and internal legal counsel regarding the likelihood of loss and amounts of probable and reasonably possible losses. We also evaluated the potential impact of information gained through the Company and third parties' investigations into the cause of the fires, information from claimants, the advice of legal counsel, and reading external information for any evidence that might contradict management's assertions.
- We evaluated the estimation methodology for determining the amount of probable and reasonably possible losses through inquiries with management and external and internal legal counsel and we tested the significant assumptions, including certain settlements, used in the estimates of probable and reasonably possible losses.
- We read legal letters from the Company's external and internal legal counsel regarding known information and evaluated whether the information therein was consistent with the information obtained in our procedures.
- We evaluated whether the Company's disclosures were appropriate and consistent with the information obtained in our procedures.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
February 21, 2025

We have served as the Company's auditor since 1991.

BERKSHIRE HATHAWAY ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Amounts in millions)

	As of December 31,	
	2024	2023
ASSETS		
Current assets:		
Cash and cash equivalents	\$ 1,392	\$ 1,565
Investments and restricted cash and cash equivalents	216	1,253
Trade receivables, net	2,551	2,667
Inventories	1,962	1,509
Mortgage loans held for sale	528	451
Regulatory assets	1,136	1,398
Other current assets	1,314	1,355
Total current assets	9,099	10,198
Property, plant and equipment, net	103,769	99,248
Goodwill	11,413	11,547
Regulatory assets	4,213	4,167
Investments and restricted cash and cash equivalents and investments	8,635	9,510
Other assets	3,011	3,170
Total assets	\$ 140,140	\$ 137,840

The accompanying notes are an integral part of these consolidated financial statements.

BERKSHIRE HATHAWAY ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (continued)
(Amounts in millions, except share amounts)

	As of December 31,	
	2024	2023
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	\$ 2,928	\$ 3,175
Accrued interest	728	625
Accrued property, income and other taxes	1,043	828
Accrued employee expenses	364	354
Short-term debt	1,123	4,148
Current portion of long-term debt	2,646	2,740
Other current liabilities	2,109	1,551
Total current liabilities	10,941	13,421
BHE senior debt	11,457	13,101
BHE junior subordinated debentures	—	100
Subsidiary debt	41,154	36,231
Regulatory liabilities	6,754	6,644
Deferred income taxes	12,628	12,437
Other long-term liabilities	5,917	6,166
Total liabilities	88,851	88,100
Commitments and contingencies (Note 16)		
Equity:		
BHE shareholders' equity:		
Preferred stock - 100,000,000 shares authorized, \$0.01 par value, 481,000 and — shares issued and outstanding	481	—
Common stock - 100 and 115,000,000 shares authorized, no par value, 1 and 75,627,913 shares issued and outstanding	—	—
Additional paid-in capital	5,558	5,573
Retained earnings	46,311	44,765
Accumulated other comprehensive loss, net	(2,341)	(1,904)
Total BHE shareholders' equity	50,009	48,434
Noncontrolling interests	1,280	1,306
Total equity	51,289	49,740
Total liabilities and equity	\$ 140,140	\$ 137,840

The accompanying notes are an integral part of these consolidated financial statements.

BERKSHIRE HATHAWAY ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2024	2023	2022
Operating revenue:			
Energy	\$ 21,566	\$ 21,280	\$ 21,069
Real estate	4,354	4,322	5,268
Total operating revenue	25,920	25,602	26,337
Operating expenses:			
Energy:			
Cost of sales	6,616	7,057	6,757
Operations and maintenance	5,125	4,779	4,153
Wildfire losses, net of recoveries (Note 16)	346	1,677	64
Depreciation and amortization	4,138	4,170	4,230
Property and other taxes	840	823	775
Real estate	4,509	4,316	5,117
Total operating expenses	21,574	22,822	21,096
Operating income	4,346	2,780	5,241
Other income (expense):			
Interest expense	(2,716)	(2,415)	(2,216)
Capitalized interest	188	132	76
Allowance for equity funds	352	267	167
Interest and dividend income	443	412	154
Gains (losses) on marketable securities, net	474	669	(2,002)
Other, net	86	116	(7)
Total other income (expense)	(1,173)	(819)	(3,828)
Income before income tax expense (benefit) and equity income (loss)	3,173	1,961	1,413
Income tax expense (benefit)	(1,582)	(1,699)	(1,916)
Equity income (loss)	(318)	(288)	(185)
Net income	4,437	3,372	3,144
Net income attributable to noncontrolling interests	137	352	423
Net income attributable to BHE shareholders	4,300	3,020	2,721
Preferred dividends	—	34	46
Earnings on common shares	\$ 4,300	\$ 2,986	\$ 2,675

The accompanying notes are an integral part of these consolidated financial statements.

BERKSHIRE HATHAWAY ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Amounts in millions)

	Years Ended December 31,		
	2024	2023	2022
Net income	\$ 4,437	\$ 3,372	\$ 3,144
Other comprehensive (loss) income, net of tax:			
Unrecognized amounts on retirement benefits, net of tax of \$(1), \$(13) and \$(23)	5	(36)	(72)
Foreign currency translation adjustment	(449)	346	(810)
Unrealized gains (losses) on cash flow hedges, net of tax of \$2, \$(13) and \$20	7	(64)	76
Total other comprehensive (loss) income, net of tax	(437)	246	(806)
Comprehensive income	4,000	3,618	2,338
Comprehensive income attributable to noncontrolling interests	137	352	426
Comprehensive income attributable to BHE shareholders	\$ 3,863	\$ 3,266	\$ 1,912

The accompanying notes are an integral part of these consolidated financial statements.

BERKSHIRE HATHAWAY ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(Amounts in millions)

	BHE Shareholders' Equity							Total Equity
	Preferred Stock	Common Stock	Additional Paid-in Capital	Long-term Income Tax Receivable	Retained Earnings	Accumulated Other Comprehensive (Loss), Net	Noncontrolling Interests	
Balance, December 31, 2021	\$ 1,650	\$ —	\$ 6,374	\$ (744)	\$ 40,754	\$ (1,340)	\$ 3,895	\$ 50,589
Net income	—	—	—	—	2,721	—	421	3,142
Other comprehensive (loss) income	—	—	—	—	—	(809)	3	(806)
Long-term income tax receivable adjustments	—	—	—	744	(791)	—	—	(47)
Preferred stock redemptions	(800)	—	—	—	—	—	—	(800)
Preferred stock dividend	—	—	—	—	(46)	—	—	(46)
Common stock repurchases	—	—	(77)	—	(793)	—	—	(870)
Distributions	—	—	—	—	—	—	(522)	(522)
Contributions	—	—	—	—	—	—	5	5
Other equity transactions	—	—	1	—	(12)	—	5	(6)
Balance, December 31, 2022	850	—	6,298	—	41,833	(2,149)	3,807	50,639
Net income	—	—	—	—	3,020	—	352	3,372
Other comprehensive income	—	—	—	—	—	246	—	246
Long-term income tax receivable adjustments	—	—	—	—	(54)	—	—	(54)
Preferred stock redemptions	(850)	—	—	—	—	—	—	(850)
Preferred stock dividend	—	—	—	—	(34)	—	—	(34)
Distributions	—	—	—	—	—	—	(394)	(394)
Contributions	—	—	—	—	—	—	4	4
Purchase of Cove Point noncontrolling interest	—	—	(725)	—	—	(1)	(2,454)	(3,180)
Other equity transactions	—	—	—	—	—	—	(9)	(9)
Balance, December 31, 2023	—	—	5,573	—	44,765	(1,904)	1,306	49,740
Net income	—	—	—	—	4,300	—	137	4,437
Other comprehensive loss	—	—	—	—	—	(437)	—	(437)
Long-term income tax receivable adjustments	—	—	—	—	(33)	—	—	(33)
Common stock repurchases	—	—	(155)	—	(2,721)	—	—	(2,876)
Distributions	—	—	—	—	—	—	(162)	(162)
BHE B Merger	481	—	140	—	—	—	—	621
Other equity transactions	—	—	—	—	—	—	(1)	(1)
Balance, December 31, 2024	<u>\$ 481</u>	<u>\$ —</u>	<u>\$ 5,558</u>	<u>\$ —</u>	<u>\$ 46,311</u>	<u>\$ (2,341)</u>	<u>\$ 1,280</u>	<u>\$ 51,289</u>

The accompanying notes are an integral part of these consolidated financial statements.

BERKSHIRE HATHAWAY ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Amounts in millions)

	Years Ended December 31,		
	2024	2023	2022
Cash flows from operating activities:			
Net income	\$ 4,437	\$ 3,372	\$ 3,144
Adjustments to reconcile net income to net cash flows from operating activities:			
(Gains) losses on marketable securities, net	(474)	(669)	2,002
Depreciation and amortization	4,184	4,220	4,286
Allowance for equity funds	(352)	(267)	(167)
Equity (income) loss, net of distributions	452	415	319
Net power cost deferrals	(41)	(629)	(1,290)
Amortization of net power cost deferrals	584	354	357
Other changes in regulatory assets and liabilities	(198)	(260)	(146)
Deferred income taxes and investment tax credits, net	(267)	(257)	(467)
Other, net	50	(46)	59
Changes in other operating assets and liabilities, net of effects from acquisitions:			
Trade receivables and other assets	(542)	(134)	150
Derivative collateral, net	18	(226)	121
Pension and other postretirement benefit plans	(19)	(10)	(27)
Accrued property, income and other taxes, net	144	(58)	397
Accounts payable and other liabilities	252	280	579
Wildfires insurance receivable	401	(253)	(130)
Wildfires liability	(187)	1,300	172
Net cash flows from operating activities	<u>8,442</u>	<u>7,132</u>	<u>9,359</u>
Cash flows from investing activities:			
Capital expenditures	(9,013)	(9,148)	(7,505)
Acquisitions, net of cash acquired	—	—	(314)
Purchases of marketable securities	(354)	(314)	(574)
Proceeds from sales of marketable securities	2,615	2,520	2,464
Purchases of U.S. Treasury Bills	(2,013)	(4,282)	(1,918)
Proceeds from sales of U.S. Treasury Bills	1,975	1,809	—
Proceeds from maturities of U.S. Treasury Bills	723	3,507	—
Equity method investments	(12)	(12)	119
Other, net	44	21	(22)
Net cash flows from investing activities	<u>(6,035)</u>	<u>(5,899)</u>	<u>(7,750)</u>
Cash flows from financing activities:			
Preferred stock redemptions	—	(850)	(800)
Preferred dividends	—	(38)	(50)
Common stock repurchases	(2,276)	—	(870)
Repayment of note payable	(600)	—	—
Proceeds from BHE senior debt	—	—	986
Repayments of BHE senior debt	—	(900)	—
Repayments of BHE junior subordinated debt	(91)	—	—
Proceeds from subsidiary debt	6,358	4,084	2,887
Repayments of subsidiary debt	(2,794)	(2,821)	(1,494)
Net (repayments of) proceeds from short-term debt	(3,017)	3,024	(867)
Purchase of Cove Point noncontrolling interest	—	(3,300)	—
Distributions to noncontrolling interests	(163)	(395)	(524)
Other, net	(37)	(54)	(274)
Net cash flows from financing activities	<u>(2,620)</u>	<u>(1,250)</u>	<u>(1,006)</u>
Effect of exchange rate changes	(12)	11	(30)
Net change in cash and cash equivalents and restricted cash and cash equivalents	(225)	(6)	573
Cash and cash equivalents and restricted cash and cash equivalents at beginning of period	1,811	1,817	1,244
Cash and cash equivalents and restricted cash and cash equivalents at end of period	<u>\$ 1,586</u>	<u>\$ 1,811</u>	<u>\$ 1,817</u>

The accompanying notes are an integral part of these consolidated financial statements.

BERKSHIRE HATHAWAY ENERGY COMPANY AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Organization and Operations

Berkshire Hathaway Energy Company ("BHE"), a wholly owned subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway"), is a holding company headquartered in Iowa that has investments in a highly diversified portfolio of locally managed and operated businesses principally engaged in the energy industry (collectively with its subsidiaries, the "Company").

The Company's operations are organized as eight business segments: PacifiCorp and its subsidiaries ("PacifiCorp"), MidAmerican Funding, LLC and its subsidiaries ("MidAmerican Funding") (which primarily consists of MidAmerican Energy Company ("MidAmerican Energy")), NV Energy, Inc. and its subsidiaries ("NV Energy") (which primarily consists of Nevada Power Company and its subsidiaries ("Nevada Power") and Sierra Pacific Power Company and its subsidiaries ("Sierra Pacific")), Northern Powergrid Holdings Company and its subsidiaries ("Northern Powergrid") (which primarily consists of Northern Powergrid (Northeast) plc and Northern Powergrid (Yorkshire) plc), BHE Pipeline Group, LLC and its subsidiaries (which primarily consists of BHE GT&S, LLC and its subsidiaries ("BHE GT&S")), Northern Natural Gas Company ("Northern Natural Gas") and Kern River Gas Transmission Company ("Kern River")), BHE Transmission (which consists of BHE Canada Holdings Corporation and its subsidiaries ("BHE Canada") (which primarily consists of AltaLink, L.P. ("AltaLink")) and BHE U.S. Transmission, LLC and its subsidiaries), BHE Renewables, LLC and its subsidiaries ("BHE Renewables") and HomeServices of America, Inc. and its subsidiaries ("HomeServices"). The Company, through these locally managed and operated businesses, has investments in four utility companies in the U.S. serving customers in 11 states, two electricity distribution companies in Great Britain, five interstate natural gas pipeline companies and interests in a liquefied natural gas ("LNG") export, import and storage facility in the U.S., an electric transmission business in Canada, interests in electric transmission businesses in the U.S., a renewable energy business primarily investing in wind, solar, geothermal and hydroelectric projects, the largest residential real estate brokerage firm in the U.S. and one of the largest residential real estate brokerage franchise networks in the U.S.

(2) Summary of Significant Accounting Policies

Basis of Consolidation and Presentation

The Consolidated Financial Statements include the accounts of BHE and its subsidiaries in which it holds a controlling financial interest as of the financial statement date. The Consolidated Statements of Operations include the revenue and expenses of any acquired entities from the date of acquisition. The Company consolidates variable interest entities ("VIE") in which it possesses both (i) the power to direct the activities that most significantly impact the entity's economic performance and (ii) the obligation to absorb losses or receive benefits from the entity that could potentially be significant to the VIE. Intercompany accounts and transactions have been eliminated.

Use of Estimates in Preparation of Financial Statements

The preparation of the Consolidated Financial Statements in conformity with accounting principles generally accepted in the United States of America ("GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the period. These estimates include, but are not limited to, the effects of regulation; impairment of goodwill; recovery of long-lived assets; certain assumptions made in accounting for pension and other postretirement benefits; asset retirement obligations ("AROs"); income taxes; unbilled revenue; valuation of certain financial assets and liabilities, including derivative contracts; and accounting for loss contingencies and applicable insurance recoveries, including those related to the Oregon and Northern California 2020 wildfires (the "2020 Wildfires") and a wildfire that began in the Oak Knoll Ranger District of the Klamath National Forest in Siskiyou County, California in July 2022 (the "2022 McKinney Fire"), referred to together as "the Wildfires" as discussed in Note 16. Actual results may differ from the estimates used in preparing the Consolidated Financial Statements.

Accounting for the Effects of Certain Types of Regulation

PacifiCorp, MidAmerican Energy, Nevada Power, Sierra Pacific, BHE GT&S, Northern Natural Gas, Kern River and AltaLink (the "Regulated Businesses") prepare their financial statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, the Regulated Businesses defer the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in regulated rates occur. If it becomes no longer probable that the deferred costs or income will be included in future regulated rates, the related regulatory assets and liabilities will be recognized in net income, returned to customers or re-established as accumulated other comprehensive income (loss) ("AOCI").

Fair Value Measurements

As defined under GAAP, fair value is the price that would be received to sell an asset or paid to transfer a liability between market participants in the principal market or in the most advantageous market when no principal market exists. Adjustments to transaction prices or quoted market prices may be required in illiquid or disorderly markets in order to estimate fair value. Alternative valuation techniques may be appropriate under the circumstances to determine the value that would be received to sell an asset or paid to transfer a liability in an orderly transaction. Market participants are assumed to be independent, knowledgeable, able and willing to transact an exchange and not under duress. Nonperformance or credit risk is considered when determining fair value. Considerable judgment may be required in interpreting market data used to develop the estimates of fair value. Accordingly, estimates of fair value presented herein are not necessarily indicative of the amounts that could be realized in a current or future market exchange.

Cash and Cash Equivalents and Restricted Cash and Cash Equivalents

Cash equivalents consist of funds invested in money market mutual funds, U.S. Treasury Bills and other investments with a maturity of three months or less when purchased. Cash and cash equivalents exclude amounts where availability is restricted by legal requirements, loan agreements or other contractual provisions. Restricted cash and cash equivalents consist substantially of funds restricted for debt service obligations for certain of the Company's nonregulated renewable energy projects. A reconciliation of cash and cash equivalents and restricted cash and cash equivalents as of December 31, 2024 and 2023, as presented on the Consolidated Statements of Cash Flows is outlined below and disaggregated by the line items in which they appear on the Consolidated Balance Sheets (in millions):

	As of December 31,	
	2024	2023
Cash and cash equivalents	\$ 1,392	\$ 1,565
Investments and restricted cash and cash equivalents	177	224
Investments and restricted cash and cash equivalents and investments	17	22
Total cash and cash equivalents and restricted cash and cash equivalents	<u>\$ 1,586</u>	<u>\$ 1,811</u>

Investments

Fixed Maturity Securities

The Company's management determines the appropriate classification of investments in fixed maturity securities at the acquisition date and reevaluates the classification at each balance sheet date. Investments and restricted cash and cash equivalents and investments that management does not intend to use or is restricted from using in current operations are presented as noncurrent on the Consolidated Balance Sheets.

Available-for-sale investments are carried at fair value with realized gains and losses, as determined on a specific identification basis, recognized in earnings and unrealized gains and losses recognized in AOCI, net of tax. Realized and unrealized gains and losses on fixed maturity securities in a trust related to the decommissioning of nuclear generation assets are recorded as a net regulatory liability since the Company expects to recover costs for these activities through regulated rates. Trading investments are carried at fair value with changes in fair value recognized in earnings. Held-to-maturity investments are carried at amortized cost, reflecting the ability and intent to hold the securities to maturity. The difference between the original cost and maturity value of a fixed maturity security is amortized to earnings using the interest method.

Investment gains and losses arise when investments are sold (as determined on a specific identification basis) or are other-than-temporarily impaired with respect to securities classified as available-for-sale. If the value of a fixed maturity investment declines to below amortized cost and the decline is deemed other than temporary, the amortized cost of the investment is reduced to fair value, with a corresponding charge to earnings. Any resulting impairment loss is recognized in earnings if the Company intends to sell, or expects to be required to sell, the debt security before its amortized cost is recovered. If the Company does not expect to ultimately recover the amortized cost basis even if it does not intend to sell the security, the credit loss component is recognized in earnings and any difference between fair value and the amortized cost basis, net of the credit loss, is reflected in other comprehensive income (loss) ("OCI"). For regulated fixed maturity investments, any impairment charge is offset by the establishment of a regulatory asset to the extent recovery in regulated rates is probable.

Equity Securities

Investments in equity securities are carried at fair value with changes in fair value recognized in earnings as a component of gains (losses) on marketable securities, net. All changes in fair value of equity securities in a trust related to the decommissioning of nuclear generation assets are recorded as a net regulatory liability since the Company expects to recover costs for these activities through regulated rates.

Equity Method Investments

The Company utilizes the equity method of accounting with respect to investments when it possesses the ability to exercise significant influence, but not control, over the operating and financial policies of the investee. The ability to exercise significant influence is presumed when the investor possesses more than 20% of the voting interests of the investee. This presumption may be overcome based on specific facts and circumstances that demonstrate that the ability to exercise significant influence is restricted. In applying the equity method, the Company records the investment at cost and subsequently increases or decreases the carrying value of the investment by the Company's share of the net earnings or losses and OCI of the investee. The Company records dividends or other equity distributions as reductions in the carrying value of the investment. Certain equity investments are presented on the Consolidated Balance Sheets net of related investment tax credits.

Allowance for Credit Losses

Trade receivables are primarily short-term in nature with stated collection terms of less than one year from the date of origination and are stated at the outstanding principal amount, net of an estimated allowance for credit losses. The allowance for credit losses is based on the Company's assessment of the collectability of amounts owed to the Company by its customers. This assessment requires judgment regarding the ability of customers to pay or the outcome of any pending disputes. In measuring the allowance for credit losses for trade receivables, the Company primarily utilizes credit loss history. However, the Company may adjust the allowance for credit losses to reflect current conditions and reasonable and supportable forecasts that deviate from historical experience. The changes in the balance of the allowance for credit losses, which is included in trade receivables, net on the Consolidated Balance Sheets, is summarized as follows for the years ended December 31 (in millions):

	<u>2024</u>	<u>2023</u>	<u>2022</u>
Beginning balance	\$ 102	\$ 106	\$ 108
Charged to operating costs and expenses, net	61	68	43
Write-offs, net	(84)	(72)	(45)
Ending balance	<u>\$ 79</u>	<u>\$ 102</u>	<u>\$ 106</u>

Derivatives

The Company employs a number of different derivative contracts, which may include forwards, futures, options, swaps and other agreements, to manage its commodity price, interest rate, and foreign currency exchange rate risk. Derivative contracts are recorded on the Consolidated Balance Sheets as either assets or liabilities and are stated at estimated fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by GAAP. Derivative balances reflect offsetting permitted under master netting agreements with counterparties and cash collateral paid or received under such agreements. Cash collateral received from or paid to counterparties to secure derivative contract assets or liabilities in excess of amounts offset is included in other current assets on the Consolidated Balance Sheets.

Commodity derivatives used in normal business operations that are settled by physical delivery, among other criteria, are eligible for and may be designated as normal purchases or normal sales. Normal purchases or normal sales contracts are not marked-to-market and settled amounts are recognized as operating revenue or cost of sales on the Consolidated Statements of Operations.

For the Company's derivatives not designated as hedging contracts, the settled amount is generally included in regulated rates. Accordingly, the net unrealized gains and losses associated with interim price movements on contracts that are accounted for as derivatives and probable of inclusion in regulated rates are recorded as regulatory assets and liabilities. For the Company's derivatives not designated as hedging contracts and for which changes in fair value are not recorded as regulatory assets and liabilities, unrealized gains and losses are recognized on the Consolidated Statements of Operations as operating revenue for sales contracts; cost of sales and operating expense for purchase contracts and electricity, natural gas and fuel swap contracts; and other, net for interest rate swap derivatives.

For the Company's derivatives designated as hedging contracts, the Company formally assesses, at inception and thereafter, whether the hedging contract is highly effective in offsetting changes in the hedged item. The Company formally documents hedging activity by transaction type and risk management strategy. For derivative instruments that are accounted for as cash flow hedges or fair value hedges, the cash flows from the derivatives and from the related hedged items are classified in operating cash flows.

Changes in the estimated fair value of a derivative contract designated and qualified as a cash flow hedge, to the extent effective, are included on the Consolidated Statements of Changes in Equity as AOCI, net of tax, until the contract settles and the hedged item is recognized in earnings. The Company discontinues hedge accounting prospectively when it has determined that a derivative contract no longer qualifies as an effective hedge, or when it is no longer probable that the hedged forecasted transaction will occur. When hedge accounting is discontinued because the derivative contract no longer qualifies as an effective hedge, future changes in the estimated fair value of the derivative contract are charged to earnings. Gains and losses related to discontinued hedges that were previously recorded in AOCI will remain in AOCI until the contract settles and the hedged item is recognized in earnings, unless it becomes probable that the hedged forecasted transaction will not occur at which time associated deferred amounts in AOCI are immediately recognized in earnings.

Inventories

Inventories consist mainly of fuel, which includes coal stocks, stored gas and fuel oil, totaling \$422 million and \$250 million as of December 31, 2024 and 2023, respectively, and materials and supplies totaling \$1,540 million and \$1,259 million as of December 31, 2024 and 2023, respectively. The cost of materials and supplies, coal stocks and fuel oil is determined primarily using the average cost method. The cost of stored gas is determined using either the last-in-first-out ("LIFO") method or the lower of average cost or market. With respect to inventories carried at LIFO cost, the replacement cost would be \$18 million and \$4 million higher as of December 31, 2024 and 2023, respectively.

Property, Plant and Equipment, Net

General

Additions to property, plant and equipment are recorded at cost. The Company capitalizes all construction-related materials, direct labor and contract services, as well as indirect construction costs. Indirect construction costs include capitalized interest, including debt allowance for funds used during construction ("AFUDC"), and equity AFUDC, as applicable to the Regulated Businesses. The cost of additions and betterments are capitalized, while costs incurred that do not improve or extend the useful lives of the related assets are generally expensed. Additionally, MidAmerican Energy has regulatory arrangements in Iowa in which the carrying cost of certain utility plant has been reduced for amounts associated with electric returns on equity exceeding specified thresholds.

Depreciation and amortization are generally computed by applying the composite or straight-line method based on either estimated useful lives or mandated recovery periods as prescribed by the Company's various regulatory authorities. Depreciation studies are completed by the Regulated Businesses to determine the appropriate group lives, net salvage and group depreciation rates. These studies are reviewed and rates are ultimately approved by the applicable regulatory commission. Net salvage includes the estimated future residual values of the assets and any estimated removal costs recovered through approved depreciation rates. Estimated removal costs are recorded as either a cost of removal regulatory liability or an ARO liability on the Consolidated Balance Sheets, depending on whether the obligation meets the requirements of an ARO. As actual removal costs are incurred, the associated liability is reduced.

Generally when the Company retires or sells a component of regulated property, plant and equipment, it charges the original cost, net of any proceeds from the disposition, to accumulated depreciation. Any gain or loss on disposals of all other assets is recorded through earnings.

Debt and equity AFUDC, which represent the estimated costs of debt and equity funds necessary to finance the construction of regulated facilities, is capitalized by the Regulated Businesses as a component of property, plant and equipment, with offsetting credits to the Consolidated Statements of Operations. AFUDC is computed based on guidelines set forth by the Federal Energy Regulatory Commission ("FERC") and the Alberta Utilities Commission. After construction is completed, the Company is permitted to earn a return on these costs as a component of the related assets, as well as recover these costs through depreciation expense over the useful lives of the related assets.

Asset Retirement Obligations

The Company recognizes AROs when it has a legal obligation to perform decommissioning, reclamation or removal activities upon retirement of an asset. The Company's AROs are primarily related to the decommissioning of nuclear generating facilities and obligations associated with its other generating facilities and offshore natural gas pipelines. The fair value of an ARO liability is recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made, and is added to the carrying amount of the associated asset, which is then depreciated over the remaining useful life of the asset. Subsequent to the initial recognition, the ARO liability is adjusted for any revisions to the original estimate of undiscounted cash flows (with corresponding adjustments to property, plant and equipment, net) and for accretion of the ARO liability due to the passage of time. For the Regulated Businesses, the difference between the ARO liability, the corresponding ARO asset included in property, plant and equipment, net and amounts recovered in rates to satisfy such liabilities is recorded as a regulatory asset or liability.

Impairment

The Company evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or when the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value and any resulting impairment loss is reflected on the Consolidated Statements of Operations. As a majority of all property, plant and equipment is used in regulated businesses, the impacts of regulation are considered when evaluating the carrying value of regulated assets.

Leases

The Company has non-cancelable operating leases primarily for office space, office equipment, generating facilities, land and rail cars and finance leases consisting primarily of transmission assets, generating facilities and vehicles. These leases generally require the Company to pay for insurance, taxes and maintenance applicable to the leased property. Given the capital-intensive nature of the utility industry, it is common for a portion of lease costs to be capitalized when used during construction or maintenance of assets, in which the associated costs will be capitalized with the corresponding asset and depreciated over the remaining life of that asset. Certain leases contain renewal options for varying periods and escalation clauses for adjusting rent to reflect changes in price indices. The Company does not include options in its lease calculations unless there is a triggering event indicating the Company is reasonably certain to exercise the option. The Company's accounting policy is to not recognize right-of-use assets and lease obligations for leases with contract terms of one year or less and not separate lease components from non-lease components and instead account for each separate lease component and the non-lease components associated with a lease as a single lease component. Leases will be evaluated for impairment in line with Accounting Standards Codification ("ASC") 360, "Property, Plant and Equipment" when a triggering event has occurred that might affect the value and use of the assets being leased.

The Company's leases of generating facilities generally are for the long-term purchase of electric energy, also known as power purchase agreements ("PPA"). PPAs are generally signed before or during the early stages of project construction and can yield a lease that has not yet commenced. These agreements are primarily for renewable energy and the payments are considered variable lease payments as they are based on the amount of output.

The Company's operating and finance right-of-use assets are recorded in other assets and the operating and finance lease liabilities are recorded in current and long-term other liabilities accordingly.

Goodwill

Goodwill represents the excess of the purchase price over the fair value of identifiable net assets acquired in business combinations. The Company evaluates goodwill for impairment at least annually and completed its annual review as of October 31, 2024. When evaluating goodwill for impairment, the Company estimates the fair value of its reporting units. If the carrying amount of a reporting unit, including goodwill, exceeds the estimated fair value, then the excess is charged to earnings as an impairment loss. Significant judgment is required in estimating the fair value of the reporting unit and performing goodwill impairment tests. The determination of fair value incorporates significant unobservable inputs. During 2024, 2023 and 2022, the Company did not record any material goodwill impairments.

The Company records goodwill adjustments for changes to the purchase price allocation prior to the end of the measurement period, which is not to exceed one year from the acquisition date.

Revenue Recognition

Customer Revenue

The Company uses a single five-step model to identify and recognize revenue from contracts with customers ("Customer Revenue") upon transfer of control of promised goods or services in an amount that reflects the consideration to which the Company expects to be entitled in exchange for those goods or services. The Company records sales, franchise and excise taxes collected directly from customers and remitted directly to the taxing authorities on a net basis on the Consolidated Statements of Operations. In the event one of the parties to a contract has performed before the other, the Company would recognize a contract asset or contract liability depending on the relationship between the Company's performance and the customer's payment.

Energy Products and Services

A majority of the Company's energy revenue is derived from tariff-based sales arrangements approved by various regulatory commissions. These tariff-based revenues are mainly comprised of energy, transmission, distribution and natural gas and have performance obligations to deliver energy products and services to customers which are satisfied over time as energy is delivered or services are provided. The Company's energy revenue that is nonregulated primarily relates to the Company's renewable energy business.

Revenue recognized is equal to what the Company has the right to invoice as it generally corresponds directly with the value to the customer of the Company's performance to date and includes billed and unbilled amounts. As of December 31, 2024 and 2023, trade receivables, net on the Consolidated Balance Sheets relate substantially to Customer Revenue, including unbilled revenue of \$807 million and \$787 million, respectively. Payments for amounts billed are generally due from the customer within 30 days of billing. Rates charged for energy products and services are established by regulators or contractual arrangements that establish the transaction price as well as the allocation of price amongst the separate performance obligations. When preliminary regulated rates are permitted to be billed prior to final approval by the applicable regulator, certain revenue collected may be subject to refund and a liability for estimated refunds is accrued.

Real Estate Services

The Company's HomeServices reportable segment consists of separate brokerage, mortgage and franchise businesses. Rates charged for brokerage, mortgage and franchise real estate services are established through contractual arrangements that establish the transaction price and the allocation of the price amongst the separate performance obligations.

The full-service residential real estate brokerage business has performance obligations to deliver integrated real estate services including brokerage services, title and closing services, property and casualty insurance, home warranties, relocation services, and other home-related services to customers. All performance obligations related to the full-service residential real estate brokerage business are satisfied in less than one year at the point in time when a real estate transaction is closed or when services are provided. Commission revenue from real estate brokerage transactions and related amounts due to agents are recognized when a real estate transaction is closed. Title and escrow closing fee revenue from real estate transactions and related amounts due to the title insurer are recognized at closing. Payments for amounts billed are generally due from the customer at closing.

The franchise business operates a network that has performance obligations to provide the right to use certain brand names and other related service marks as well as to provide orientation programs, training and consultation services, advertising programs and other services to its franchisees. The performance obligations related to the franchise business are satisfied over time or when the services are provided. Franchise royalty fees are sales-based variable consideration and are based on a percentage of commissions earned by franchisees on real estate sales, which are recognized when the sale closes. Meetings and training revenue, referral fees, late fees, service fees and franchise termination fees are earned when services have been completed. Payments for amounts billed are generally due from the franchisee within 30 days of billing.

Other Revenue

Energy Products and Services

Other revenue consists primarily of revenue related to power purchase agreements not considered Customer Revenue as they are recognized in accordance with ASC 815, "Derivatives and Hedging" and ASC 842, "Leases" and certain non-tariff-based revenue approved by the regulator that is not considered Customer Revenue within ASC 606, "Revenue from Contracts with Customers."

Real Estate Service

Mortgage and other revenue consists primarily of revenue related to the mortgage business. Mortgage fee revenue consists of amounts earned related to application and underwriting fees and fees on canceled loans. Fees associated with the origination of mortgage loans are recognized as earned. These amounts are not considered Customer Revenue as they are recognized in accordance with ASC 815, "Derivatives and Hedging," ASC 825, "Financial Instruments" and ASC 860, "Transfers and Servicing."

Unamortized Debt Premiums, Discounts and Debt Issuance Costs

Premiums, discounts and debt issuance costs incurred for the issuance of long-term debt are amortized over the term of the related financing using the effective interest method.

Foreign Currency

The accounts of foreign-based subsidiaries are measured in most instances using the local currency of the subsidiary as the functional currency. Revenue and expenses of these businesses are translated into U.S. dollars at the average exchange rate for the period. Assets and liabilities are translated at the exchange rate as of the end of the reporting period. Gains or losses from translating the financial statements of foreign-based operations are included in equity as a component of AOCI. Gains or losses arising from transactions denominated in a currency other than the functional currency of the entity that is party to the transaction are included in earnings.

Income Taxes

The Company's provision for income taxes has been computed on a stand-alone basis. Berkshire Hathaway includes the Company in its consolidated U.S. federal and Iowa state income tax returns and the majority of the Company's U.S. federal income tax is remitted to or received from Berkshire Hathaway.

Deferred income tax assets and liabilities are based on differences between the financial statement and income tax basis of assets and liabilities using enacted income tax rates expected to be in effect for the year in which the differences are expected to reverse. Changes in deferred income tax assets and liabilities associated with components of OCI are charged or credited directly to OCI. Changes in deferred income tax assets and liabilities associated with certain property-related basis differences and other various differences that the Company's regulated businesses deems probable to be passed on to their customers are charged or credited directly to a regulatory asset or liability and will be included in regulated rates when the temporary differences reverse. Other changes in deferred income tax assets and liabilities are included as a component of income tax expense. Changes in deferred income tax assets and liabilities attributable to changes in enacted income tax rates are charged or credited to income tax expense or a regulatory asset or liability in the period of enactment. Valuation allowances are established when necessary to reduce deferred income tax assets to the amount that is more-likely-than-not to be realized.

Investment tax credits are deferred and amortized over the estimated useful lives of the related properties or as prescribed by various regulatory commissions. The Company has not established deferred income taxes on its undistributed foreign earnings that have been determined by management to be reinvested indefinitely.

The Company recognizes the tax benefit from an uncertain tax position only if it is more-likely-than-not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the Consolidated Financial Statements from such a position are measured based on the largest benefit that is more-likely-than-not to be realized upon ultimate settlement. The Company's unrecognized tax benefits are primarily included in accrued property, income and other taxes and other long-term liabilities on the Consolidated Balance Sheets. Estimated interest and penalties, if any, related to uncertain tax positions are included as a component of income tax expense (benefit) on the Consolidated Statements of Operations.

New Accounting Pronouncements

In November 2023, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2023-07, Segment Reporting Topic 280, "Segment Reporting—Improvements to Reportable Segment Disclosures" which allows disclosure of one or more measures of segment profit or loss used by the chief operating decision maker to allocate resources and assess performance. Additionally, the standard requires enhanced disclosures of significant segment expenses and other segment items as well as incremental qualitative disclosures on both an annual and interim basis. This guidance is effective for annual reporting periods beginning after December 15, 2023, and interim reporting periods after December 15, 2024. Early adoption is permitted and retrospective application is required for all periods presented. The Company adopted this guidance for the fiscal year beginning January 1, 2024 under the retrospective method. The adoption did not have a material impact on the Company's Consolidated Financial Statements but did increase the disclosures included within Notes to Consolidated Financial Statements. Refer to Note 22 for additional disclosures of certain significant segment expenses.

In December 2023, the FASB issued ASU No. 2023-09, Income Taxes Topic 740, "Income Tax—Improvements to Income Tax Disclosures" which requires enhanced disclosures, including specific categories and disaggregation of information in the effective tax rate reconciliation, disaggregated information related to income taxes paid, income or loss from continuing operations before income tax expense or benefit, and income tax expense or benefit from continuing operations. This guidance is effective for annual reporting periods beginning after December 15, 2024. Early adoption is permitted and should be applied on a prospective basis, however retrospective application is permitted. The Company is currently evaluating the impact of adopting this guidance on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

In March 2024, the United States Securities and Exchange Commission adopted final rules requiring disclosure of certain climate-related information in registration statements and Forms 10-K. The final rules require a registrant to disclose, among other things: material climate-related risks; activities to mitigate or adapt to such risks; information about the registrant's board of directors' oversight of climate-related risks and management's role in managing material climate-related risks; and information on any climate-related targets or goals that are material to the registrant's business, results of operations, or financial condition. Further, to facilitate investors' assessment of certain climate-related risks, the final rules require disclosure of Scope 1 and Scope 2 greenhouse gas emissions when those emissions are material and disclosure of the financial statement effects of severe weather events and other natural conditions. The final rules include phased-in compliance periods for all registrants, with the compliance date dependent on the registrant's filer status and the content of the disclosure. On April 4, 2024, the United States Securities and Exchange Commission voluntarily stayed implementation of the final rules, pending the completion of judicial review of consolidated challenges by the Court of Appeals for the Eighth Circuit. The Company is currently evaluating the impact of adopting the final rules on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

In November 2024, the FASB issued ASU No. 2024-03, Income Statement—Reporting Comprehensive Income—Expense Disaggregation Disclosures Subtopic 220-40, "Disaggregation of Income Statement Expenses" which addresses requests from investors for more detailed information about certain expenses and requires disclosure of the amounts of purchases of inventory, employee compensation, depreciation and intangible asset amortization included in each relevant expense caption presented on the income statement. This guidance is effective for annual reporting periods beginning after December 15, 2026 and interim reporting periods beginning after December 15, 2027. Early adoption is permitted and should be applied on a prospective basis, however retrospective application is permitted. The Company is currently evaluating the impact of adopting this guidance on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

(3) Business Acquisitions

On September 1, 2023, BHE and Eastern MLP Holding Company II, LLC ("the Buyer"), an indirect wholly owned subsidiary of BHE, completed the acquisition of DECP Holdings, Inc.'s (the "Seller"), an indirect wholly owned subsidiary of Dominion Energy, Inc., 50% limited partner interests in Cove Point LNG, LP ("Cove Point") ("The Transaction"). Under the terms of the Purchase and Sale Agreement, dated July 9, 2023 (the "Purchase Agreement"), the Buyer paid \$3.3 billion in cash, plus the pro rata portion of the quarterly distribution made by Cove Point for the third fiscal quarter of 2023. BHE funded the Transaction with cash on hand, including cash realized from the liquidation of certain investments, which was contributed to BHE GT&S. The Buyer now holds 75% of the limited partner interests, and its affiliate, Cove Point GP Holding Company, LLC, continues to hold 100% of the general partner interest, of Cove Point. Prior to the Transaction, BHE held 100% of the general partner interest and 25% of the limited partner interests in Cove Point. BHE previously determined it has the power to direct the activities that most significantly impact Cove Point's economic performance as well as the obligation to absorb losses and benefits which could be significant to it and accordingly, consolidated Cove Point. Because BHE controls Cove Point both before and after the Transaction, the changes in BHE's interest in Cove Point were accounted for as an equity transaction and no gain or loss was recognized. In connection with the Transaction, BHE recognized \$120 million of income taxes in equity primarily attributable to the step up in tax basis of the investment in Cove Point of \$144 million, partially offset by establishing additional regulatory liabilities related to excess deferred income taxes of \$24 million.

Other

In 2022, the Company completed various acquisitions totaling \$314 million, net of cash acquired. The purchase price for each acquisition was allocated to the assets acquired and liabilities assumed, which related to residential real estate brokerage businesses, 300 MWs of long-term transmission rights and 399 MWs of wind-powered generating facilities. As a result of the various acquisitions, the Company acquired assets of \$363 million, assumed liabilities of \$65 million and recognized goodwill of \$16 million.

(4) Property, Plant and Equipment, Net

Property, plant and equipment, net consists of the following as of December 31 (in millions):

	<u>Depreciable Life</u>	<u>2024</u>	<u>2023</u>
Regulated assets:			
Utility generation, transmission and distribution systems	5-80 years	\$ 103,015	\$ 96,195
Interstate natural gas pipeline assets	3-80 years	20,237	19,226
		123,252	115,421
Accumulated depreciation and amortization		(38,940)	(36,365)
Regulated assets, net		84,312	79,056
Nonregulated assets:			
Independent power plants	2-50 years	8,619	8,484
LNG facility	40 years	3,455	3,423
Other assets	2-30 years	2,766	2,874
		14,840	14,781
Accumulated depreciation and amortization		(4,176)	(3,856)
Nonregulated assets, net		10,664	10,925
		94,976	89,981
Construction in progress		8,793	9,267
Property, plant and equipment, net		<u>\$ 103,769</u>	<u>\$ 99,248</u>

Construction work-in-progress includes \$8.0 billion and \$8.6 billion as of December 31, 2024 and 2023, respectively, related to the construction of regulated assets.

(5) Jointly Owned Utility Facilities

Under joint facility ownership agreements, the Domestic Regulated Businesses, as tenants in common, have undivided interests in jointly owned generation, transmission, distribution and pipeline common facilities. The Company accounts for its proportionate share of each facility and each joint owner has provided financing for its share of each facility. Operating costs of each facility are assigned to joint owners based on their percentage of ownership or energy production, depending on the nature of the cost. Operating costs and expenses on the Consolidated Statements of Operations include the Company's share of the expenses of these facilities.

The amounts shown in the table below represent the Company's share in each jointly owned facility included in property, plant and equipment, net as of December 31, 2024 (dollars in millions):

	Company Share	Facility In Service	Accumulated Depreciation and Amortization	Construction Work-in- Progress
PacifiCorp:				
Jim Bridger Nos. 1-4	67 %	1,564	991	4
Hunter No. 1	94 %	509	256	3
Hunter No. 2	60 %	315	161	1
Wyodak	80 %	492	301	—
Colstrip Nos. 3 and 4	10 %	263	217	2
Hermiston	50 %	191	115	6
Craig Nos. 1 and 2	19 %	373	352	—
Hayden No. 1	25 %	77	58	—
Hayden No. 2	13 %	45	34	—
Transmission and distribution facilities	Various	932	296	308
Total PacifiCorp		4,761	2,781	324
MidAmerican Energy:				
Louisa No. 1	88 %	988	559	7
Quad Cities Nos. 1 and 2 ⁽¹⁾	25 %	747	501	13
Walter Scott, Jr. No. 3	79 %	1,033	679	10
Walter Scott, Jr. No. 4 ⁽²⁾	60 %	177	124	12
George Neal No. 4	41 %	337	199	5
Ottumwa No. 1 ⁽²⁾	52 %	402	306	16
George Neal No. 3	72 %	598	368	13
Transmission facilities	Various	276	103	4
Total MidAmerican Energy		4,558	2,839	80
NV Energy:				
Valmy Nos. 1 and 2	50 %	412	372	13
ON Line Transmission Line	25 %	161	41	1
Other transmission facilities	Various	63	31	33
Total NV Energy		636	444	47
BHE Pipeline Group:				
Ellisburg Pool	39 %	33	13	1
Ellisburg Station	50 %	29	9	5
Harrison	50 %	55	20	3
Leidy	50 %	148	51	4
Oakford	50 %	213	75	1
Common facilities	Various	275	183	—
Total BHE Pipeline Group		753	351	14
Total		\$ 10,708	\$ 6,415	\$ 465

(1) Includes amounts related to nuclear fuel.

(2) Facility in-service and accumulated depreciation and amortization amounts are net of credits applied under Iowa regulatory arrangements totaling \$953 million and \$218 million, respectively.

(6) Leases

The following table summarizes the Company's leases recorded on the Consolidated Balance Sheets as of December 31 (in millions):

	<u>2024</u>	<u>2023</u>
Right-of-use assets:		
Operating leases	\$ 441	\$ 501
Finance leases	399	399
Total right-of-use assets	<u>\$ 840</u>	<u>\$ 900</u>
Lease liabilities:		
Operating leases	\$ 492	\$ 555
Finance leases	412	413
Total lease liabilities	<u>\$ 904</u>	<u>\$ 968</u>

The following table summarizes the Company's lease costs for the years ended December 31 (in millions):

	<u>2024</u>	<u>2023</u>	<u>2022</u>
Variable	\$ 434	\$ 439	\$ 552
Operating	128	136	136
Finance:			
Amortization	23	21	20
Interest	34	35	36
Short-term	33	46	44
Total lease costs	<u>\$ 652</u>	<u>\$ 677</u>	<u>\$ 788</u>

Weighted-average remaining lease term (years):			
Operating leases	7.2	7.4	7.4
Finance leases	25.9	27.5	28.1

Weighted-average discount rate:			
Operating leases	5.1 %	4.5 %	4.1 %
Finance leases	8.5 %	8.6 %	8.6 %

The following table summarizes the Company's supplemental cash flow information relating to leases for the years ended December 31 (in millions):

	<u>2024</u>	<u>2023</u>	<u>2022</u>
Cash paid for amounts included in the measurement of lease liabilities:			
Operating cash flows from operating leases	\$ (131)	\$ (138)	\$ (141)
Operating cash flows from finance leases	(33)	(35)	(36)
Financing cash flows from finance leases	(29)	(27)	(25)
Right-of-use assets obtained in exchange for lease liabilities:			
Operating leases	\$ 61	\$ 71	\$ 131
Finance leases	15	6	3

The Company has the following remaining lease commitments as of December 31, 2024 (in millions):

	<u>Operating</u>	<u>Finance</u>	<u>Total</u>
2025	\$ 140	\$ 67	\$ 207
2026	116	66	182
2027	86	63	149
2028	57	57	114
2029	38	37	75
Thereafter	147	493	640
Total undiscounted lease payments	584	783	1,367
Less - amounts representing interest	(92)	(371)	(463)
Lease liabilities	<u>\$ 492</u>	<u>\$ 412</u>	<u>\$ 904</u>

(7) Regulatory Matters

Regulatory Assets

Regulatory assets represent costs that are expected to be recovered in future regulated rates. The Company's regulatory assets reflected on the Consolidated Balance Sheets consist of the following as of December 31 (in millions):

	<u>Weighted Average Remaining Life</u>	<u>2024</u>	<u>2023</u>
Deferred net power costs	1 year	\$ 1,400	\$ 1,769
Asset retirement obligations	19 years	1,031	930
Deferred income taxes ⁽¹⁾	Various	455	435
Employee benefit plans ⁽²⁾	13 years	386	414
Demand side management	9 years	281	245
Wildfire mitigation and vegetation management costs	Various	208	114
Levelized depreciation	28 years	185	167
Unrealized losses on regulated derivative contracts	1 year	182	173
Environmental costs	29 years	145	139
Asset disposition costs	Various	140	135
Cost of removal	26 years	122	143
Other	Various	814	901
Total regulatory assets		<u>\$ 5,349</u>	<u>\$ 5,565</u>
Reflected as:			
Current assets		\$ 1,136	\$ 1,398
Noncurrent assets		4,213	4,167
Total regulatory assets		<u>\$ 5,349</u>	<u>\$ 5,565</u>

(1) Amounts primarily represent income tax benefits related to certain property-related basis differences and other various differences that were previously passed on to customers and will be included in regulated rates when the temporary differences reverse.

(2) Includes amounts not yet recognized as a component of net periodic benefit cost that are expected to be included in regulated rates when recognized.

The Company had regulatory assets not earning a return on investment of \$2.1 billion and \$3.2 billion as of December 31, 2024 and 2023, respectively.

Regulatory Liabilities

Regulatory liabilities represent income to be recognized or amounts to be returned to customers in future periods. The Company's regulatory liabilities reflected on the Consolidated Balance Sheets consist of the following as of December 31 (in millions):

	Weighted Average Remaining Life	2024	2023
Cost of removal ⁽¹⁾	27 years	\$ 2,918	\$ 2,741
Deferred income taxes ⁽²⁾	Various	2,493	2,733
Asset retirement obligations	29 years	446	364
Employee benefit plans ⁽³⁾	Various	292	211
Revenue sharing mechanisms	Various	263	243
Levelized depreciation	27 years	215	230
Other	Various	406	296
Total regulatory liabilities		<u>\$ 7,033</u>	<u>\$ 6,818</u>
Reflected as:			
Current liabilities		\$ 279	\$ 174
Noncurrent liabilities		6,754	6,644
Total regulatory liabilities		<u>\$ 7,033</u>	<u>\$ 6,818</u>

- (1) Amounts represent estimated costs, as accrued through depreciation rates and exclusive of ARO liabilities, of removing regulated property, plant and equipment in accordance with accepted regulatory practices. Amounts are deducted from rate base or otherwise accrue a carrying cost.
- (2) Amounts primarily represent income tax liabilities related to the federal tax rate change from 35% to 21% that are probable to be passed on to customers, offset by income tax benefits related to certain property-related basis differences and other various differences that were previously passed on to customers and will be included in regulated rates when the temporary differences reverse.
- (3) Includes amounts not yet recognized as a component of net periodic benefit cost that are expected to be returned to customers in future periods when recognized.

(8) Investments and Restricted Cash and Cash Equivalents and Investments

Investments and restricted cash and cash equivalents and investments consists of the following as of December 31 (in millions):

	<u>2024</u>	<u>2023</u>
Investments:		
BYD Company Limited common stock	\$ 415	\$ 2,218
U.S. Treasury Bills	—	996
Rabbi trusts	525	487
Other	394	338
Total investments	<u>1,334</u>	<u>4,039</u>
Equity method investments:		
BHE Renewables tax equity investments	4,773	4,058
Electric Transmission Texas, LLC	761	673
Iroquois Gas Transmission System, L.P.	580	599
Other	339	381
Total equity method investments	<u>6,453</u>	<u>5,711</u>
Restricted cash and cash equivalents and investments:		
Quad Cities Station nuclear decommissioning trust funds	871	767
Other restricted cash and cash equivalents	194	246
Total restricted cash and cash equivalents and investments	<u>1,065</u>	<u>1,013</u>
Total investments and restricted cash and cash equivalents and investments	<u>\$ 8,852</u>	<u>\$ 10,763</u>
Reflected as:		
Other current assets	\$ 217	\$ 1,253
Noncurrent assets	8,635	9,510
Total investments and restricted cash and cash equivalents and investments	<u>\$ 8,852</u>	<u>\$ 10,763</u>

Investments

BHE's investment in BYD Company Limited common stock is accounted for as a marketable security with changes in fair value recognized in net income.

Rabbi trusts primarily hold corporate-owned life insurance on certain current and former key executives and directors. The Rabbi trusts were established to hold investments used to fund the obligations of various nonqualified executive and director compensation plans and to pay the costs of the trusts. The amount represents the cash surrender value of all of the policies included in the Rabbi trusts, net of amounts borrowed against the cash surrender value.

Gains (losses) on marketable securities, net recognized during the period consists of the following for the years ended December 31 (in millions):

	<u>2024</u>	<u>2023</u>	<u>2022</u>
Unrealized gains (losses) recognized on marketable securities held at the reporting date	\$ 110	\$ 252	\$ (1,487)
Net gains (losses) recognized on marketable securities sold during the period	364	417	(515)
Gains (losses) on marketable securities, net	<u>\$ 474</u>	<u>\$ 669</u>	<u>\$ (2,002)</u>

Equity Method Investments

The Company has invested in wind projects sponsored by third parties, commonly referred to as tax equity investments. Under the terms of these tax equity investments, the Company has entered into equity capital contribution agreements with the project sponsors that require contributions. The Company made no contributions in 2024, 2023 and 2022. Once a project achieves commercial operation, the Company enters into a partnership agreement with the project sponsor that directs and allocates the operating profits and tax benefits from the project. In December 2024, the Company acquired eight tax equity investments as part of the BHE B Inc. ("BHE B") merger as described in Note 18.

BHE, through separate subsidiaries, owns (i) 50% of Electric Transmission Texas, LLC, which owns and operates electric transmission assets in the Electric Reliability Council of Texas footprint; (ii) 50% of Iroquois, which owns and operates an interstate natural gas transmission system located in the states of New York and Connecticut; (iii) 50% of JAX LNG, LLC, which is an LNG supplier in Florida serving the growing marine and truck LNG markets; and (iv) 66.67% of Bridger Coal Company ("Bridger Coal"), which is a coal mining joint venture that supplies coal to PacifiCorp's Jim Bridger Nos. 3-4 generating facility. Bridger Coal is being accounted for under the equity method of accounting as the power to direct the activities that most significantly impact Bridger Coal's economic performance are shared with the joint venture partner. Coal purchases from Bridger Coal for the years ended December 31, 2024, 2023 and 2022 totaled \$107 million, \$115 million and \$100 million, respectively.

Restricted Investments

MidAmerican Energy has established a trust for the investment of funds for decommissioning the Quad Cities Nuclear Station Units 1 and 2 ("Quad Cities Station"). The debt and equity securities in the trust are reported at fair value. Funds are invested in the trust in accordance with applicable federal and state investment guidelines and are restricted for use as reimbursement for costs of decommissioning the Quad Cities Station, which are currently licensed for operation until December 2032.

(9) Short-term Debt and Credit Facilities

The following table summarizes BHE's and its subsidiaries' availability under their credit facilities as of December 31 (in millions):

	BHE	PacifiCorp	MidAmerican Funding	NV Energy	Northern Powergrid	BHE Canada	HomeServices	Total ⁽¹⁾
2024:								
Credit facilities ⁽²⁾	\$ 3,500	\$ 2,900	\$ 1,509	\$ 1,000	\$ 344	\$ 643	\$ 1,700	\$ 11,596
Less:								
Short-term debt	(180)	(240)	—	—	(94)	(106)	(503)	\$ (1,123)
Tax-exempt bond support and letters of credit	—	(52)	(271)	—	—	(2)	—	\$ (325)
Net credit facilities	<u>\$ 3,320</u>	<u>\$ 2,608</u>	<u>\$ 1,238</u>	<u>\$ 1,000</u>	<u>\$ 250</u>	<u>\$ 535</u>	<u>\$ 1,197</u>	<u>\$ 10,148</u>
2023:								
Credit facilities ⁽²⁾⁽³⁾	\$ 3,500	\$ 2,000	\$ 1,509	\$ 1,000	\$ 346	\$ 850	\$ 1,500	\$ 10,705
Less:								
Short-term debt	(1,935)	(1,604)	—	—	(92)	(97)	(420)	(4,148)
Tax-exempt bond support and letters of credit	—	(249)	(306)	—	—	(1)	—	(556)
Net credit facilities	<u>\$ 1,565</u>	<u>\$ 147</u>	<u>\$ 1,203</u>	<u>\$ 1,000</u>	<u>\$ 254</u>	<u>\$ 752</u>	<u>\$ 1,080</u>	<u>\$ 6,001</u>

(1) The table does not include unused credit facilities and letters of credit for investments that are accounted for under the equity method.

(2) Includes \$94 million and \$92 million, respectively, drawn on capital expenditure and other uncommitted credit facilities at Northern Powergrid as of December 31, 2024 and 2023.

(3) Excludes \$700 million from a credit facility at HomeServices that was unavailable due to borrowing restrictions pursuant to the credit agreement.

As of December 31, 2024, the Company was in compliance with the covenants of its credit facilities and letter of credit arrangements.

BHE

BHE has a \$3.5 billion unsecured credit facility expiring in June 2027 with an unlimited number of maturity extension options, subject to lender consent. This credit facility, which is for general corporate purposes, supports BHE's commercial paper program and provides for the issuance of letters of credit, has a variable interest rate based on the Secured Overnight Financing Rate ("SOFR") or a base rate, at BHE's option, plus a spread that varies based on BHE's credit ratings for its senior unsecured long-term debt securities.

As of December 31, 2024 and 2023, BHE had \$180 million and \$1.9 billion of commercial paper borrowings outstanding at a weighted average interest rate of 4.70% and 5.59%, respectively. The credit facility requires that BHE's ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.70 to 1.0 as of the last day of each quarter.

As of December 31, 2024 and 2023, BHE had \$210 million and \$300 million, respectively, of letter of credit capacity under its \$3.5 billion unsecured credit facility, of which no amounts were outstanding. Additionally, as of December 31, 2024 and 2023, BHE had \$100 million and \$105 million, respectively, of letters of credit outstanding outside of its \$3.5 billion unsecured credit facility, which primarily support power purchase agreements and debt service requirements at certain subsidiaries of BHE Renewables, LLC expiring from April 2025 through August 2045 and have provisions that automatically extend the annual expiration dates for an additional year unless the issuing bank elects not to renew a letter of credit prior to the expiration date.

PacifiCorp

PacifiCorp has a \$2.0 billion unsecured credit facility expiring in June 2027 with an unlimited number of maturity extension options, subject to lender consent. The credit facility, which supports PacifiCorp's commercial paper program and certain series of its tax-exempt bond obligations and provides for the issuance of a certain level of letters of credit, has a variable interest rate based on SOFR or a base rate, at PacifiCorp's option, plus a spread that varies based on PacifiCorp's credit ratings for its senior unsecured long-term debt securities. In addition, PacifiCorp has a \$900 million 364-day unsecured credit facility expiring in June 2025 which, similar to its other existing \$2.0 billion credit facility provides for loans at variable interest rates based on the SOFR or a base rate, at PacifiCorp's option, plus a spread that varies based on PacifiCorp's credit ratings for its senior unsecured long-term debt securities.

As of December 31, 2024 and 2023, PacifiCorp had \$240 million and \$1.6 billion of short-term debt outstanding at a weighted average rate of 4.65% and 6.16%, respectively.

The credit facilities require that PacifiCorp's ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.65 to 1.0 as of the last day of each quarter.

As of December 31, 2024, PacifiCorp had \$255 million of letter of credit capacity under its \$2.0 billion revolving credit facility of which no amount was outstanding, and \$488 million of letter of credit capacity outside of its \$2.0 billion revolving credit facility, of which \$34 million was outstanding and was utilized in support of certain transactions required by third parties. Subsequently, PacifiCorp added \$225 million of letter of credit capacity outside of its \$2.0 billion revolving credit facility. As of February 21, 2025, PacifiCorp's total letter of credit capacity outside of its \$2.0 billion revolving credit facility was \$713 million.

As of December 31, 2023, PacifiCorp had \$255 million of letter of credit capacity under the \$2.0 billion revolving credit facility of which \$31 million was outstanding and was utilized as a standby letter of credit, and \$168 million of letter of credit capacity outside of its \$2.0 billion revolving credit facility, of which \$55 million was outstanding and was utilized in support of certain transactions required by third parties.

MidAmerican Funding

As of December 31, 2024, MidAmerican Energy has a \$1.5 billion unsecured credit facility expiring in June 2027 with an unlimited number of maturity extension options, subject to lender consent. The credit facility, which supports MidAmerican Energy's commercial paper program and its variable-rate tax-exempt bond obligations and provides for the issuance of letters of credit, has a variable interest rate based on SOFR or a base rate, at MidAmerican Energy's option, plus a spread that varies based on MidAmerican Energy's credit ratings for senior unsecured long-term debt securities. Additionally, MidAmerican Energy has a \$5 million unsecured credit facility, which expires June 2025 and has a variable interest rate based on SOFR, plus a spread.

As of December 31, 2024 and 2023, MidAmerican Energy had no commercial paper borrowings outstanding. The \$1.5 billion credit facility requires that MidAmerican Energy's ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.65 to 1.0 as of the last day of any quarter.

As of December 31, 2024 and 2023, MidAmerican Energy had \$135 million and \$345 million, respectively, of letter of credit capacity under its \$1.5 billion unsecured credit facility, of which no amounts were outstanding. Additionally, as of December 31, 2024 and 2023, MidAmerican Energy had \$53 million and \$55 million, respectively, of letters of credit outstanding outside of its \$1.5 billion unsecured credit facility in support of certain transactions required by third parties that generally have provisions that automatically extend the annual expiration dates for an additional year unless the issuing bank elects not to renew a letter of credit prior to the expiration date.

NV Energy

Nevada Power has a \$600 million secured credit facility expiring in June 2027 and Sierra Pacific has a \$400 million secured credit facility expiring in June 2027 each with an unlimited number of maturity extension options, subject to lender consent. These credit facilities, which are for general corporate purposes and provide for the issuance of letters of credit, have a variable interest rate based on SOFR or a base rate, at each of the Nevada Utilities' option, plus a spread that varies based on each of the Nevada Utilities' credit ratings for its senior secured long-term debt securities. As of December 31, 2024 and 2023, the Nevada Utilities had no borrowings outstanding under the credit facility. Amounts due under each credit facility are collateralized by each of the Nevada Utilities' general and refunding mortgage bonds. These credit facilities require that each of the Nevada Utilities' ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.65 to 1.0 as of the last day of each quarter.

As of December 31, 2024 and 2023, Nevada Power had \$50 million of letter of credit capacity under its \$600 million secured credit facility and Sierra Pacific had \$50 million of letter of credit capacity under its \$400 million secured credit facility, of which no amounts were outstanding.

Northern Powergrid

Northern Powergrid has a £200 million unsecured credit facility expiring in December 2026. The credit facility has a variable interest rate based on Sterling Overnight Index Average plus a spread that varies based on Northern Powergrid's credit ratings and a credit adjustment spread that varies based on the tenor of any borrowings. The credit facility requires that the ratio of consolidated senior total net debt, including current maturities, to regulated asset value not exceed 0.8 to 1.0 at Northern Powergrid and 0.65 to 1.0 at each of Northern Powergrid (Northeast) plc and Northern Powergrid (Yorkshire) plc as of June 30 and December 31. Northern Powergrid's interest coverage ratio shall not be less than 2.5 to 1.0.

As of December 31, 2024 and 2023, Northern Powergrid had no amounts outstanding under the credit facility.

BHE Canada

BHE Canada has a C\$50 million unsecured revolving term credit facility expiring in December 2027 with a recurring one-year extension option subject to lender consent. In February 2025, the credit agreement was amended, extending the expiration date to December 2028. The credit facility, which may be used for general corporate purposes and letters of credit, has a variable interest rate based on the Canadian bank prime lending rate, or a spread above the Canadian Overnight Repo Rate Average ("CORRA"), at BHE Canada's option, based on BHE Canada's senior unsecured credit rating. The credit facility requires the ratio of consolidated total debt to consolidated total capitalization not exceed 0.75 to 1.0 measured as of the last day of each quarter. In addition, BHE Canada is required to maintain a ratio of unconsolidated earnings before interest, taxes, depreciation and amortization to interest expense of not less than 2.25 to 1.00 measured as of the last day of each quarter.

As of December 31, 2024 and 2023, BHE Canada had no borrowings outstanding under the credit facility.

As of December 31, 2024 and 2023, BHE Canada had C\$50 million of letter of credit capacity under its C\$50 million unsecured revolving term credit facility, of which \$1 million and \$— million, respectively were outstanding.

AltaLink

AltaLink has a C\$500 million secured revolving term credit facility expiring in December 2029 with a recurring one-year extension option subject to lender consent. The credit facility, which supports AltaLink's commercial paper program and may also be used for general corporate purposes, has a variable interest rate based on the Canadian bank prime lending rate or a spread above CORRA, at AltaLink's option, based on AltaLink's senior secured credit rating.

As of December 31, 2024 and 2023, AltaLink had \$106 million and \$97 million outstanding under the facility at a weighted average interest rate of 3.32% and 5.24%, respectively. The credit facility requires the ratio of consolidated indebtedness to total capitalization not exceed 0.75 to 1.0 measured as of the last day of each quarter.

AltaLink also has a C\$75 million secured revolving term credit facility expiring in December 2029 with a recurring one-year extension option subject to lender consent. The credit facility, which may be used for general corporate purposes and letters of credit, has a variable interest rate based on the Canadian bank prime lending rate, or a spread above CORRA, at AltaLink's option, based on AltaLink's senior secured credit rating.

As of December 31, 2024 and 2023, AltaLink had no borrowings outstanding under the facility. The credit facility requires the ratio of consolidated indebtedness to total capitalization not exceed 0.75 to 1.0 measured as of the last day of each quarter.

As of December 31, 2024 and 2023, AltaLink had C\$75 million of letter of credit capacity under its C\$75 million secured revolving term credit facility, of which \$1 million and \$1 million, respectively were outstanding.

AltaLink Investments, L.P. has a C\$300 million unsecured revolving term credit facility expiring in December 2027 with a recurring one-year extension option subject to lender consent. The credit facility, which may be used for general corporate purposes and letters of credit, has a variable interest rate based on the Canadian bank prime lending rate, or a spread above the Bankers' Acceptance rate, at AltaLink Investments, L.P.'s option, based on AltaLink Investments, L.P.'s senior unsecured credit rating.

As of December 31 2023, AltaLink Investments, L.P. also had a C\$200 million revolving term credit facility. The credit facility, could be used for general corporate purposes and letters of credit, had a variable interest rate based on the Canadian bank prime lending rate, or a spread above CORRA, at AltaLink Investments, L.P.'s option, based on AltaLink Investments, L.P.'s credit ratings for its senior unsecured credit rating. This facility was terminated on January 8, 2024.

As of December 31, 2024 and 2023, AltaLink Investments, L.P. had no amounts outstanding under these facilities. The credit facilities require the ratio of consolidated total debt to capitalization not exceed 0.8 to 1.0 and earnings before interest, taxes, depreciation and amortization to interest expense for the four fiscal quarters ended not be less than 2.25 to 1.0 measured as of the last day of each quarter.

As of December 31, 2024 and 2023, AltaLink Investments, L.P. had C\$10 million of letter of credit capacity under its C\$300 million unsecured revolving term credit facility, of which no amounts were outstanding.

As of December 31, 2023, AltaLink Investments, L.P. had C\$10 million of letter of credit capacity under its C\$200 million revolving term credit facility, of which no amounts were outstanding.

HomeServices

As of December 31, 2024 HomeServices has a \$200 million secured credit facility expiring in September 2026. The credit facility, which is for general corporate purposes and provides for the issuance of letters of credit, has a variable interest rate based on SOFR or a base rate, at HomeServices' option, plus a spread that varies based on HomeServices' total net leverage ratio as of the last day of each quarter. As of December 31, 2024, HomeServices had no amounts outstanding under its credit facility.

Through its subsidiaries, HomeServices maintains mortgage lines of credit totaling \$1.5 billion as of December 31, 2024 and 2023, used for mortgage banking activities that expire beginning in March 2025 through July 2025. The mortgage lines of credit have variable rates based on SOFR, plus a spread. Collateral for these credit facilities is comprised of residential property being financed and is equal to the loans funded with the facilities. As of December 31, 2024 and 2023, HomeServices had \$503 million and \$420 million, respectively, outstanding under these mortgage lines of credit at a weighted average interest rate of 5.88% and 6.92%, respectively.

BHE Renewables Letters of Credit

As of December 31, 2024 and 2023, certain renewable projects collectively have letters of credit outstanding of \$287 million and \$311 million, respectively, primarily in support of the power purchase agreements and large generator interconnection agreements associated with the projects.

(10) BHE Debt*Senior Debt*

BHE senior debt represents unsecured senior obligations of BHE that are redeemable in whole or in part at any time generally with make whole premiums. BHE senior debt consists of the following, including fair value adjustments and unamortized premiums, discounts and debt issuance costs, as of December 31 (in millions):

	Par Value	2024	2023
3.50% Senior Notes, due 2025	\$ 400	\$ 400	\$ 399
4.05% Senior Notes, due 2025	1,250	1,250	1,248
3.25% Senior Notes, due 2028	600	597	593
8.48% Senior Notes, due 2028	256	257	264
3.70% Senior Notes, due 2030	1,100	1,097	1,096
1.65% Senior Notes, due 2031	500	498	498
6.125% Senior Bonds, due 2036	1,670	1,663	1,663
5.95% Senior Bonds, due 2037	550	548	548
6.50% Senior Bonds, due 2037	225	223	223
5.15% Senior Notes, due 2043	750	741	741
4.50% Senior Notes, due 2045	750	739	739
3.80% Senior Notes, due 2048	750	738	736
4.45% Senior Notes, due 2049	1,000	991	990
4.25% Senior Notes, due 2050	900	889	889
2.85% Senior Notes, due 2051	1,500	1,489	1,488
4.60% Senior Notes, due 2053	1,000	987	986
Total BHE Senior Debt	\$ 13,201	\$ 13,107	\$ 13,101
Reflected as:			
Current liabilities		\$ 1,650	\$ —
Noncurrent liabilities		11,457	13,101
Total BHE Senior Debt		\$ 13,107	\$ 13,101

Junior Subordinated Debentures

BHE junior subordinated debentures consists of the following as of December 31 (in millions):

	Par Value	2024	2023
5.00% Junior subordinated debentures, due 2057	\$ —	\$ —	\$ 100
Total BHE junior subordinated debentures - noncurrent	\$ —	\$ —	\$ 100

In September 2024, BHE acquired, cancelled and extinguished the junior subordinated debentures held by a minority shareholder. Interest expense to the minority shareholder was \$4 million, \$5 million and \$5 million for the years ended December 31, 2024, 2023 and 2022.

(11) Subsidiary Debt

BHE's direct and indirect subsidiaries are organized as legal entities separate and apart from BHE and its other subsidiaries. Pursuant to separate financing agreements, substantially all of PacifiCorp's electric utility properties; the equity interest of MidAmerican Funding's subsidiary; MidAmerican Energy's electric utility properties in the state of Iowa; substantially all of Nevada Power's and Sierra Pacific's properties in the state of Nevada; AltaLink's transmission properties; and substantially all of the assets of the subsidiaries of BHE Renewables that are direct or indirect owners of wind and solar generation projects are pledged or encumbered to support or otherwise provide the security for their related subsidiary debt. It should not be assumed that the assets of any subsidiary will be available to satisfy BHE's obligations or the obligations of its other subsidiaries. However, unrestricted cash or other assets which are available for distribution may, subject to applicable law, regulatory commitments and the terms of financing and ring-fencing arrangements for such parties, be advanced, loaned, paid as dividends or otherwise distributed or contributed to BHE or affiliates thereof. The long-term debt of BHE's subsidiaries may include provisions that allow BHE's subsidiaries to redeem such debt in whole or in part at any time. These provisions generally include make-whole premiums.

Distributions at these separate legal entities are limited by various covenants including, among others, leverage ratios, interest coverage ratios and debt service coverage ratios. As of December 31, 2024, all subsidiaries were in compliance with their long-term debt covenants.

Long-term debt of subsidiaries consists of the following, including fair value adjustments and unamortized premiums, discounts and debt issuance costs, as of December 31 (in millions):

	<u>Par Value</u>	<u>2024</u>	<u>2023</u>
PacifiCorp	\$ 13,702	\$ 13,588	\$ 10,410
MidAmerican Funding	9,176	9,053	8,992
NV Energy	4,971	4,932	4,695
Northern Powergrid	3,367	3,337	3,465
BHE Pipeline Group	5,359	5,582	5,154
BHE Transmission	3,285	3,267	3,574
BHE Renewables	2,350	2,331	2,548
HomeServices	60	60	133
Total subsidiary debt	<u><u>\$ 42,270</u></u>	<u><u>\$ 42,150</u></u>	<u><u>\$ 38,971</u></u>
Reflected as:			
Current liabilities		\$ 996	\$ 2,740
Noncurrent liabilities		41,154	36,231
Total subsidiary debt		<u><u>\$ 42,150</u></u>	<u><u>\$ 38,971</u></u>

PacifiCorp's long-term debt consists of the following, including unamortized premiums, discounts and debt issuance costs as of December 31 (dollars in millions):

	Par Value	2024	2023
First mortgage bonds:			
3.60%, due 2024	\$ —	\$ —	\$ 425
3.35%, due 2025	250	250	250
6.71%, due 2026	100	100	99
5.10%, due 2029	500	498	—
3.50%, due 2029	400	399	399
2.70%, due 2030	400	398	398
5.30%, due 2031	700	696	—
7.70%, due 2031	300	299	299
5.45%, due 2034	1,100	1,093	—
5.90%, due 2034	200	199	199
5.25%, due 2035	300	299	299
6.10%, due 2036	350	348	348
5.75%, due 2037	600	600	600
6.25%, due 2037	600	598	597
6.35%, due 2038	300	298	298
6.00%, due 2039	650	644	644
4.10%, due 2042	300	298	298
4.125%, due 2049	600	594	594
4.15%, due 2050	600	594	593
3.30%, due 2051	600	591	591
2.90%, due 2052	1,000	985	985
5.35%, due 2053	1,100	1,088	1,087
5.50%, due 2054	1,200	1,189	1,189
5.80%, due 2055	1,500	1,478	—
Variable-rate series, tax-exempt bond obligations (2024-3.20% to 4.45%; 2023-4.60% to 5.60%):			
Secured ⁽¹⁾ , due 2024	—	—	166
Secured ⁽¹⁾ , due 2025	27	27	27
Unsecured, due 2025	25	25	25
Total PacifiCorp	\$ 13,702	\$ 13,588	\$ 10,410

(1) Secured by pledged first mortgage bonds registered to and held by the tax-exempt bond trustee generally with the same interest rates, maturity dates and redemption provisions as the tax-exempt bond obligations.

PacifiCorp currently has regulatory authority from the Oregon Public Utility Commission and the Idaho Public Utilities Commission to issue an additional \$5.0 billion of long-term debt. PacifiCorp must make a notice filing with the Washington Utilities and Transportation Commission prior to any future issuance. PacifiCorp currently has an effective shelf registration statement filed with the U.S. Securities and Exchange Commission to issue an indeterminate amount of first mortgage bonds and unsecured debt securities through July 2027.

The issuance of PacifiCorp's first mortgage bonds is limited by available property, earnings tests and other provisions of PacifiCorp's mortgage. Approximately \$39.0 billion of PacifiCorp's eligible property (based on original cost) was subject to the lien of the mortgage as of December 31, 2024.

MidAmerican Funding

MidAmerican Funding's long-term debt consists of the following, including fair value adjustments and unamortized premiums, discounts and debt issuance costs, as of December 31 (dollars in millions):

	<u>Par Value</u>	<u>2024</u>	<u>2023</u>
MidAmerican Funding:			
6.927% Senior Bonds, due 2029	\$ 239	\$ 240	\$ 240
Fair value adjustment	—	(11)	(14)
MidAmerican Funding, net of fair value adjustments	<u>239</u>	<u>229</u>	<u>226</u>
MidAmerican Energy:			
First mortgage bonds:			
3.50%, due 2024	—	—	500
3.10%, due 2027	375	374	374
3.65%, due 2029	850	857	858
5.35%, due 2034	350	347	347
4.80%, due 2043	350	347	347
4.40%, due 2044	400	396	396
4.25%, due 2046	450	446	446
3.95%, due 2047	475	471	471
3.65%, due 2048	700	690	690
4.25%, due 2049	900	876	876
3.15%, due 2050	600	593	592
2.70%, due 2052	500	493	492
5.85%, due 2054	1,000	990	989
5.30%, due 2055	600	592	—
Notes:			
6.75% Series, due 2031	400	398	398
5.75% Series, due 2035	300	299	299
5.80% Series, due 2036	350	348	348
Transmission upgrade obligation, 3.30% to 7.90%, due 2036 to 2043	66	37	39
Tax-exempt bond obligations -			
Variable-rate tax-exempt bond obligation series: (weighted average interest rate - 2024-3.36%, 2023-4.81%), due 2024-2047	271	270	304
Total MidAmerican Energy	<u>8,937</u>	<u>8,824</u>	<u>8,766</u>
Total MidAmerican Funding	<u>\$ 9,176</u>	<u>\$ 9,053</u>	<u>\$ 8,992</u>

Pursuant to MidAmerican Energy's mortgage dated September 9, 2013, MidAmerican Energy's first mortgage bonds, currently and from time to time outstanding, are secured by a first mortgage lien on substantially all of its electric generating, transmission and distribution property within the state of Iowa, subject to certain exceptions and permitted encumbrances. Approximately \$25 billion of MidAmerican Energy's eligible property, based on original cost, was subject to the lien of the mortgage as of December 31, 2024. Additionally, MidAmerican Energy's senior notes outstanding are equally and ratably secured with the first mortgage bonds as required by the indentures under which the senior notes were issued.

MidAmerican Energy's variable-rate tax-exempt bond obligations bear interest at rates that are periodically established through remarketing of the bonds in the short-term tax-exempt market. MidAmerican Energy, at its option, may change the mode of interest calculation for these bonds by selecting from among several floating or fixed rate alternatives. The interest rates shown in the table above are the weighted average interest rates as of December 31, 2024 and 2023. MidAmerican Energy maintains revolving credit facility agreements to provide liquidity for holders of these issues. Additionally, MidAmerican Energy's obligations associated with the \$30 million and \$150 million variable rate, tax-exempt bond obligations due 2046 and 2047, respectively, are secured by an equal amount of first mortgage bonds pursuant to MidAmerican Energy's mortgage dated September 9, 2013, as supplemented and amended.

NV Energy

NV Energy's long-term debt consists of the following, including fair value adjustments and unamortized premiums, discounts and debt issuance costs, as of December 31 (dollars in millions):

	Par Value	2024	2023
Nevada Power:			
General and refunding mortgage securities:			
3.70% Series CC, due 2029	\$ 500	\$ 498	\$ 498
2.40% Series DD, due 2030	425	423	423
6.65% Series N, due 2036	367	361	360
6.75% Series R, due 2037	349	347	346
5.375% Series X, due 2040	250	248	248
5.45% Series Y, due 2041	250	240	240
3.125% Series EE, due 2050	300	298	298
5.90% Series GG, due 2053	400	394	394
6.00% Series 2023A, due 2054	500	495	494
Tax-exempt refunding revenue bond obligations:			
Fixed-rate series:			
4.125% Pollution Control Bonds Series 2017A, due 2032 ⁽¹⁾	40	39	39
3.75% Pollution Control Bonds Series 2017, due 2036 ⁽¹⁾	40	39	39
3.75% Pollution Control Bonds Series 2017B, due 2039 ⁽¹⁾	13	13	13
Total Nevada Power	3,434	3,395	3,392
Fair value adjustments	—	9	9
Total Nevada Power, net of fair value adjustments	3,434	3,404	3,401
Sierra Pacific:			
General and refunding mortgage securities:			
2.60% Series U, due 2026	400	399	398
6.75% Series P, due 2037	252	254	254
4.71% Series W, due 2052	250	248	248
5.90% Series 2023A, due 2054	400	394	393
Tax-exempt refunding revenue bond obligations:			
Fixed-rate series:			
3.55% Pollution Control Series 2016A, due 2029	20	20	—
3.55% Pollution Control Series 2016B, due 2029 ⁽²⁾	30	29	—
3.625% Gas and Water Series 2016B, due 2036 ⁽³⁾	60	59	—
4.125% Water Facilities Series 2016C, due 2036 ⁽³⁾	30	30	—
4.125% Water Facilities Series 2016F, due 2036 ⁽³⁾	75	74	—
3.625% Water Facilities Series 2016G, due 2036 ⁽³⁾	20	20	—
Total Sierra Pacific	1,537	1,527	1,293
Fair value adjustments	—	1	1
Total Sierra Pacific, net of fair value adjustment	1,537	1,528	1,294
Total NV Energy	\$ 4,971	\$ 4,932	\$ 4,695

(1) Subject to mandatory purchase by Nevada Power in March 2026 at which date the interest rate may be adjusted.

(2) Subject to mandatory sinking fund redemption by Sierra Pacific in the principal amount of \$10 million in April 2026.

(3) Subject to mandatory purchase by Sierra Pacific in October 2029 at which date the interest rate may be adjusted.

In February 2025, Nevada Power issued \$300 million of its 6.25% Fixed-to-Fixed Reset Rate Junior Subordinated Notes due 2055. Nevada Power will pay interest on the Notes at a rate of 6.25% through May 2030, subject to a reset every 5 years. Nevada Power intends to use the net proceeds from the sale of the notes to fund capital expenditures and for general corporate purposes.

The issuance of General and Refunding Mortgage Securities by the Nevada Utilities are subject to Public Utilities Commission of Nevada ("PUCN") approval and are limited by available property and other provisions of the mortgage indentures for each of Nevada Power and Sierra Pacific. As of December 31, 2024, approximately \$11.5 billion of Nevada Power's and \$5.2 billion of Sierra Pacific's (based on original cost) property was subject to the liens of the mortgages.

Northern Powergrid

Northern Powergrid and its subsidiaries' long-term debt consists of the following, including fair value adjustments and unamortized premiums, discounts and debt issuance costs, as of December 31 (dollars in millions):

	<u>Par Value⁽¹⁾</u>	<u>2024</u>	<u>2023</u>
2.50% Bonds, due 2025	\$ 188	\$ 187	\$ 191
2.073% European Investment Bank loan, due 2025	62	63	65
2.564% European Investment Bank loans, due 2027	312	313	317
7.25% Bonds, due 2028	232	234	238
4.375% Bonds, due 2032	188	186	189
5.625% Bonds, due 2033	313	309	314
5.125% Bonds, due 2035	250	248	252
5.125% Bonds, due 2035	188	186	189
2.75% Bonds, due 2049	188	185	188
3.25% Bonds, due 2052	438	433	442
2.25% Bonds, due 2059	375	368	374
1.875% Bonds, due 2062	375	369	375
Variable-rate loan, due 2025 ⁽²⁾	137	137	158
Variable-rate loan, due 2026 ⁽³⁾	121	119	173
Total Northern Powergrid	\$ 3,367	\$ 3,337	\$ 3,465

(1) The par values for these debt instruments are denominated in sterling.

(2) Amortizes quarterly and the loan is 70% floating and 30% fixed. The Company has entered into an interest rate swap that fixes the interest rate on 100% of the floating rate portion. The variable interest rate as of December 31, 2024, was 6.47% (including 2.00% margin) and the average fixed interest rate was 3.08% (including 2.00% margin).

(3) Amortizes semiannually and the Company has entered into an interest rate swap that fixes the interest rate on 80% of the outstanding debt. The variable interest rate as of December 31, 2024 was 6.50% (including 1.65% margin) and the fixed interest rate was 2.55% (including 1.65% margin), resulting in a blended rate of 3.34%.

BHE Pipeline Group

BHE Pipeline Group's long-term debt consists of the following, including fair value adjustments and unamortized premiums, discounts and debt issuance costs, as of December 31 (dollars in millions):

	<u>Par Value</u>	<u>2024</u>	<u>2023</u>
Eastern Energy Gas:			
2.50% Senior Notes, due 2024	\$ —	\$ —	\$ 600
3.60% Senior Notes, due 2024	—	—	339
3.317% Senior Notes, due 2026 (€250) ⁽¹⁾	259	259	274
3.00% Senior Notes, due 2029	174	173	173
3.80% Senior Notes, due 2031	150	150	150
4.80% Senior Notes, due 2043	54	53	53
4.60% Senior Notes, due 2044	56	56	56
3.90% Senior Notes, due 2049	27	26	26
5.65% Senior Notes, due 2054	900	892	—
EGTS:			
3.60% Senior Notes, due 2024	—	—	111
3.00% Senior Notes, due 2029	426	423	422
5.02% Senior Notes, due 2034	150	149	—
4.80% Senior Notes, due 2043	346	342	342
4.60% Senior Notes, due 2044	444	437	437
3.90% Senior Notes, due 2049	273	271	271
Total Eastern Energy Gas	3,259	3,231	3,254
Fair value adjustments	—	268	312
Total Eastern Energy Gas, net of fair value adjustments	3,259	3,499	3,566
Northern Natural Gas:			
5.80% Senior Bonds, due 2037	150	149	149
4.10% Senior Bonds, due 2042	250	248	248
4.30% Senior Bonds, due 2049	650	651	651
3.40% Senior Bonds, due 2051	550	540	540
5.625% Senior Bonds, due 2054	500	495	—
Total Northern Natural Gas	2,100	2,083	1,588
Total BHE Pipeline Group	\$ 5,359	\$ 5,582	\$ 5,154

- (1) The senior notes are denominated in Euros with an outstanding principal balance of €250 million and a fixed interest rate of 1.45%. Eastern Energy Gas has entered into cross currency swaps that fix USD payments for 100% of the notes. The fixed USD outstanding principal when combined with the swaps is \$280 million, with fixed interest rates at both December 31, 2024 and 2023 that averaged 3.317%.

In January 2025, Eastern Energy Gas issued \$700 million of 5.80% Senior Notes due 2035 and \$500 million of 6.20% Senior Notes due 2055. Eastern Energy Gas used the net proceeds from the sale of the notes to rebalance its capitalization structure by returning a portion of the equity capital received from its indirect parent, BHE.

BHE Transmission

BHE Transmission's long-term debt consists of the following, including fair value adjustments and unamortized premiums, discounts and debt issuance costs, as of December 31 (dollars in millions):

	<u>Par Value⁽¹⁾</u>	<u>2024</u>	<u>2023</u>
AltaLink, L.P.:			
Series 2014-1 Notes, 3.399%, due 2024	\$ —	\$ —	\$ 264
Series 2016-1 Notes, 2.747%, due 2026	243	243	264
Series 2020-1 Notes, 1.509%, due 2030	157	156	169
Series 2022-1 Notes, 4.692%, due 2032	191	190	207
Series 2006-1 Notes, 5.249%, due 2036	104	104	113
Series 2010-1 Notes, 5.381%, due 2040	87	87	94
Series 2010-2 Notes, 4.872%, due 2040	104	104	113
Series 2011-1 Notes, 4.462%, due 2041	191	190	207
Series 2012-1 Notes, 3.99%, due 2042	365	360	391
Series 2013-3 Notes, 4.922%, due 2043	243	242	263
Series 2014-3 Notes, 4.054%, due 2044	205	204	222
Series 2015-1 Notes, 4.09%, due 2045	243	242	263
Series 2016-2 Notes, 3.717%, due 2046	313	311	338
Series 2013-1 Notes, 4.446%, due 2053	174	173	188
Series 2024-1 Notes, 4.742%, due 2054	226	225	—
Series 2023-1 Notes, 5.463%, due 2055	348	346	375
Series 2014-2 Notes, 4.274%, due 2064	91	90	98
Total AltaLink, L.P.	3,285	3,267	3,569
Other:			
Construction Loan, 5.62%, due 2024	—	—	5
Total BHE Transmission	<u><u>\$ 3,285</u></u>	<u><u>\$ 3,267</u></u>	<u><u>\$ 3,574</u></u>

(1) The par values for these debt instruments are denominated in Canadian dollars.

BHE Renewables

BHE Renewables' long-term debt consists of the following, including unamortized premiums, discounts and debt issuance costs, as of December 31 (dollars in millions):

	Par Value	2024	2023
Fixed-rate ⁽¹⁾ :			
Bishop Hill Holdings Senior Notes, 5.125%, due 2032	\$ 47	\$ 47	\$ 50
Solar Star Funding Senior Notes, 3.95%, due 2035	214	213	228
Solar Star Funding Senior Notes, 5.375%, due 2035	698	693	739
Grande Prairie Wind Senior Notes, 3.86%, due 2037	201	200	234
Topaz Solar Farms Senior Notes, 5.75%, due 2039	508	504	536
Topaz Solar Farms Senior Notes, 4.875%, due 2039	141	140	151
Alamo 6 Senior Notes, 4.17%, due 2042	171	169	179
Variable-rate ⁽¹⁾ :			
TX Jumbo Road Term Loan, due 2025 ⁽²⁾	48	48	72
Marshall Wind Term Loan, due 2026 ⁽²⁾	42	41	49
Pinyon Pines I and II Term Loans, due 2034 ⁽²⁾	280	276	310
Total BHE Renewables	\$ 2,350	\$ 2,331	\$ 2,548

(1) Amortizes quarterly or semiannually.

(2) The term loans have variable interest rates based on SOFR plus a margin that varies during the terms of the agreements. The Company has entered into interest rate swaps that fix the interest rate on 100% of the TX Jumbo Road, Marshall Wind and Pinyon Pines outstanding debt. The fixed interest rates as of December 31, 2024 ranged from 3.31% to 3.73%. The fixed interest rates as of December 31, 2023 ranged from 3.23% to 3.88%.

HomeServices

HomeServices' long-term debt consists of the following, including unamortized premiums, discounts and debt issuance costs, as of December 31 (dollars in millions):

	Par Value	2024	2023
Variable-rate:			
Variable-rate term loan (2024 - 7.41%, 2023 - 6.27%), due 2026 ⁽¹⁾	\$ 60	\$ 60	\$ 133

(1) Term loan amortizes quarterly and variable-rate resets monthly.

Annual Repayments of Long-Term Debt

The annual repayments of BHE and subsidiary debt for the years beginning January 1, 2025 and thereafter, excluding fair value adjustments and unamortized premiums, discounts and debt issuance costs, are as follows (in millions):

	2025	2026	2027	2028	2029	2030 and Thereafter	Total
BHE senior notes	\$ 1,650	\$ —	\$ —	\$ 856	\$ —	\$ 10,695	\$ 13,201
PacifiCorp	302	100	—	—	900	12,400	13,702
MidAmerican Funding	17	4	379	4	1,093	7,679	9,176
NV Energy	—	410	—	—	540	4,021	4,971
Northern Powergrid	431	77	313	232	—	2,314	3,367
BHE Pipeline Group	—	259	—	—	600	4,500	5,359
BHE Transmission	—	244	—	—	—	3,041	3,285
BHE Renewables	240	218	168	175	182	1,367	2,350
HomeServices	6	54	—	—	—	—	60
Totals	\$ 2,646	\$ 1,366	\$ 860	\$ 1,267	\$ 3,315	\$ 46,017	\$ 55,471

(12) Income Taxes

The Company's provision for income taxes has been computed on a stand-alone basis. Berkshire Hathaway includes the Company in its consolidated U.S. federal and Iowa state income tax returns and the majority of the Company's U.S. federal income tax is remitted to or received from Berkshire Hathaway. The Company had a current income tax payable to Berkshire Hathaway of \$138 million and a current income tax receivable from Berkshire Hathaway of \$96 million for federal income tax as of December 31, 2024 and 2023, respectively. In July 2022, the Company amended its tax allocation agreement with Berkshire Hathaway, which changed how state tax attributes will be settled with respect to state income tax returns that Berkshire Hathaway includes the Company. As a result, the Company no longer expects to receive the cash benefits from the state of Iowa net operating loss carryforward previously recorded as a long-term income tax receivable from Berkshire Hathaway as a component of BHE's shareholders' equity, and recognized a noncash distribution of \$744 million to retained earnings.

Income tax expense (benefit) consists of the following for the years ended December 31 (in millions):

	2024	2023	2022
Current:			
Federal	\$ (1,333)	\$ (1,650)	\$ (1,463)
State	(16)	118	(65)
Foreign	34	90	79
	<u>(1,315)</u>	<u>(1,442)</u>	<u>(1,449)</u>
Deferred:			
Federal	(371)	(114)	(408)
State	(29)	(275)	(49)
Foreign	94	33	(5)
	<u>(306)</u>	<u>(356)</u>	<u>(462)</u>
Investment tax credits	39	99	(5)
Total	<u>\$ (1,582)</u>	<u>\$ (1,699)</u>	<u>\$ (1,916)</u>

A reconciliation of the federal statutory income tax rate to the effective income tax rate applicable to income before income tax expense (benefit) is as follows for the years ended December 31:

	2024	2023	2022
Federal statutory income tax rate	21 %	21 %	21 %
Income tax credits	(59)	(85)	(124)
Effects of ratemaking	(6)	(11)	(16)
State income tax, net of federal income tax benefit	(1)	(6)	(6)
Non-controlling interest	(1)	(4)	(6)
Income tax effect of foreign income	(2)	(1)	(4)
Tax rate change - deferred (foreign)	—	2	—
Equity earnings	(2)	(3)	(3)
Other, net	—	—	2
Effective income tax rate	<u>(50)%</u>	<u>(87)%</u>	<u>(136)%</u>

Income tax credits relate primarily to production tax credits ("PTC") from wind- and solar-powered generating facilities owned by MidAmerican Energy, PacifiCorp, NV Energy and BHE Renewables. Federal renewable electricity PTCs are earned as energy from qualifying wind- and solar-powered generating facilities is produced and sold and are based on a per-kilowatt hour rate pursuant to the applicable federal income tax law. Wind- and solar-powered generating facilities are eligible for the credits for 10 years from the date the qualifying generating facilities are placed in-service. PTCs recognized for the years ended December 31, 2024, 2023 and 2022 totaled \$1.9 billion, \$1.7 billion, and \$1.7 billion, respectively.

The net deferred income tax liability consists of the following as of December 31 (in millions):

	2024	2023
Deferred income tax assets:		
Regulatory liabilities	\$ 1,290	\$ 1,248
Federal, state and foreign carryforwards	686	774
AROs	347	318
Loss contingency	434	431
Other	649	629
Total deferred income tax assets	3,406	3,400
Valuation allowances	(78)	(142)
Total deferred income tax assets, net	3,328	3,258
Deferred income tax liabilities:		
Property-related items	(12,949)	(12,596)
Investments	(1,505)	(1,574)
Regulatory assets	(1,124)	(1,034)
Other	(378)	(491)
Total deferred income tax liabilities	(15,956)	(15,695)
Net deferred income tax liability	<u>\$ (12,628)</u>	<u>\$ (12,437)</u>

The following table provides, without regard to valuation allowances, the Company's net operating loss and tax credit carryforwards and expiration dates as of December 31, 2024 (in millions):

	Federal	State	Foreign	Total
Net operating loss carryforwards ⁽¹⁾	\$ 58	\$ 13,441	\$ 334	\$ 13,833
Deferred income taxes on net operating loss carryforwards	12	561	77	650
Expiration dates	2025 - indefinite	2025 - indefinite	2028 - 2044	
Tax credits	\$ 14	\$ 22	\$ —	\$ 36
Expiration dates	2025 - 2034	2025 - indefinite		

(1) The federal net operating loss carryforwards relate principally to net operating loss carryforwards of subsidiaries that are tax residents in both the U.S. and the United Kingdom. The federal net operating loss carryforwards were generated prior to Berkshire Hathaway's ownership and began to expire in 2022.

The U.S. Internal Revenue Service has closed or effectively settled its examination of the Company's income tax returns through December 31, 2013. The statute of limitations for the Company's income tax returns have expired for certain states through December 31, 2011, and for other states through December 31, 2020, except for the impact of any federal audit adjustments. The closure of examinations, or the expiration of the statute of limitations, for state filings may not preclude the state from adjusting the state net operating loss carryforward utilized in a year for which the statute of limitations is not closed.

A reconciliation of the beginning and ending balances of the Company's net unrecognized tax benefits is as follows for the years ended December 31 (in millions):

	<u>2024</u>	<u>2023</u>
Beginning balance	\$ 73	\$ 68
Additions based on tax positions related to the current year	6	10
Additions for tax positions of prior years	4	1
Reductions based on tax positions related to the current year	(7)	(6)
Statute of limitations	—	(1)
Settlements	(2)	—
Interest and penalties	2	1
Ending balance	<u>\$ 76</u>	<u>\$ 73</u>

As of December 31, 2024 and 2023, the Company had unrecognized tax benefits totaling \$95 million and \$88 million, respectively, that if recognized, would have an impact on the effective tax rate. The remaining unrecognized tax benefits relate to tax positions for which ultimate deductibility is highly certain but for which there is uncertainty as to the timing of such deductibility. Recognition of these tax benefits, other than applicable interest and penalties, would not affect the Company's effective income tax rate.

(13) Employee Benefit Plans

Defined Benefit Plans

Domestic Operations

PacifiCorp, MidAmerican Energy and NV Energy sponsor defined benefit pension plans that cover a majority of all employees of BHE and its domestic energy subsidiaries. These pension plans include noncontributory defined benefit pension plans, supplemental executive retirement plans ("SERP") and restoration plans. PacifiCorp, MidAmerican Energy and NV Energy also provide certain postretirement healthcare and life insurance benefits through various plans to eligible retirees.

Net Periodic Benefit Cost (Credit)

For purposes of calculating the expected return on plan assets, a market-related value is used. The market-related value of plan assets is generally calculated by spreading the difference between expected and actual investment returns over a five-year period beginning after the first year in which they occur.

Net periodic benefit cost for the plans included the following components for the years ended December 31 (in millions):

	<u>Pension</u>			<u>Other Postretirement</u>		
	<u>2024</u>	<u>2023</u>	<u>2022</u>	<u>2024</u>	<u>2023</u>	<u>2022</u>
Service cost	\$ 14	\$ 15	\$ 22	\$ 7	\$ 8	\$ 11
Interest cost	105	110	83	29	30	20
Expected return on plan assets	(126)	(123)	(108)	(36)	(33)	(29)
Curtailement	(1)	—	(10)	—	—	—
Settlement	—	(3)	17	—	—	—
Net amortization	9	14	19	(1)	(2)	(1)
Net periodic benefit cost	<u>\$ 1</u>	<u>\$ 13</u>	<u>\$ 23</u>	<u>\$ (1)</u>	<u>\$ 3</u>	<u>\$ 1</u>

Funded Status

The following table is a reconciliation of the fair value of plan assets for the years ended December 31 (in millions):

	Pension		Other Postretirement	
	2024	2023	2024	2023
Plan assets at fair value, beginning of year	\$ 2,069	\$ 2,013	\$ 665	\$ 614
Employer contributions	13	14	7	6
Participant contributions	—	—	6	8
Actual return on plan assets	105	219	63	86
Benefits paid	(177)	(177)	(50)	(49)
Plan assets at fair value, end of year	<u>\$ 2,010</u>	<u>\$ 2,069</u>	<u>\$ 691</u>	<u>\$ 665</u>

The following table is a reconciliation of the benefit obligations for the years ended December 31 (in millions):

	Pension		Other Postretirement	
	2024	2023	2024	2023
Benefit obligation, beginning of year	\$ 2,050	\$ 2,040	\$ 565	\$ 569
Service cost	14	15	7	8
Interest cost	105	110	29	30
Participant contributions	—	—	6	8
Actuarial (gain) loss	(57)	62	(45)	(1)
Amendment	(3)	—	—	—
Benefits paid	(177)	(177)	(50)	(49)
Benefit obligation, end of year	<u>\$ 1,932</u>	<u>\$ 2,050</u>	<u>\$ 512</u>	<u>\$ 565</u>
Accumulated benefit obligation, end of year	<u>\$ 1,900</u>	<u>\$ 2,013</u>		

The funded status of the plans and the amounts recognized on the Consolidated Balance Sheets as of December 31 are as follows (in millions):

	Pension		Other Postretirement	
	2024	2023	2024	2023
Plan assets at fair value, end of year	\$ 2,010	\$ 2,069	\$ 691	\$ 665
Benefit obligation, end of year	1,932	2,050	512	565
Funded status	<u>\$ 78</u>	<u>\$ 19</u>	<u>\$ 179</u>	<u>\$ 100</u>
Amounts recognized on the Consolidated Balance Sheets:				
Other assets	\$ 209	\$ 160	\$ 183	\$ 104
Other current liabilities	(13)	(13)	—	—
Other long-term liabilities	(118)	(128)	(4)	(4)
Amounts recognized	<u>\$ 78</u>	<u>\$ 19</u>	<u>\$ 179</u>	<u>\$ 100</u>

The SERPs and restoration plan have no plan assets; however, the Company has Rabbi trusts that hold corporate-owned life insurance and other investments to provide funding for the future cash requirements of the SERPs and restoration plan. The cash surrender value of all of the policies included in the Rabbi trusts, net of amounts borrowed against the cash surrender value, plus the fair market value of other Rabbi trust investments, was \$371 million and \$341 million as of December 31, 2024 and 2023, respectively. These assets are not included in the plan assets in the above table, but are reflected in noncurrent investments and restricted cash and investments on the Consolidated Balance Sheets. The projected and accumulated benefit obligations for the SERP were \$131 million and \$141 million at December 31, 2024 and 2023, respectively.

Unrecognized Amounts

The portion of the funded status of the plans not yet recognized in net periodic benefit cost as of December 31 is as follows (in millions):

	Pension		Other Postretirement	
	2024	2023	2024	2023
Net loss (gain)	\$ 283	\$ 325	\$ (158)	\$ (88)
Prior service (credit) cost	(5)	(3)	18	20
Regulatory deferrals	19	22	—	—
Total	<u>\$ 297</u>	<u>\$ 344</u>	<u>\$ (140)</u>	<u>\$ (68)</u>

A reconciliation of the amounts not yet recognized as components of net periodic benefit cost for the years ended December 31, 2024 and 2023 is as follows (in millions):

	Regulatory Assets (Liabilities)	Accumulated Other Comprehensive Loss (Income)	Total
<u>Pension</u>			
Balance, December 31, 2022	<u>\$ 390</u>	<u>\$ —</u>	<u>\$ 390</u>
Net gain arising during the year	(35)	—	(35)
Settlement	3	—	3
Net amortization	(13)	(1)	(14)
Total	<u>(45)</u>	<u>(1)</u>	<u>(46)</u>
Balance, December 31, 2023	<u>345</u>	<u>(1)</u>	<u>344</u>
Net gain arising during the year	(30)	(5)	(35)
Net prior service credit arising during the year	(3)	—	(3)
Net amortization	(9)	—	(9)
Total	<u>(42)</u>	<u>(5)</u>	<u>(47)</u>
Balance, December 31, 2024	<u>\$ 303</u>	<u>\$ (6)</u>	<u>\$ 297</u>

	Regulatory Assets (Liabilities)	Accumulated Other Comprehensive Loss (Income)	Total
<u>Other Postretirement</u>			
Balance, December 31, 2022	\$ (14)	\$ (2)	\$ (16)
Net gain arising during the year	(51)	(3)	(54)
Net amortization	2	—	2
Total	(49)	(3)	(52)
Balance, December 31, 2023	(63)	(5)	(68)
Net gain arising during the year	(68)	(5)	(73)
Net amortization	1	—	1
Total	(67)	(5)	(72)
Balance, December 31, 2024	<u>\$ (130)</u>	<u>\$ (10)</u>	<u>\$ (140)</u>

Plan Assumptions

Weighted-average assumptions used to determine benefit obligations and net periodic benefit cost were as follows:

	Pension			Other Postretirement		
	2024	2023	2022	2024	2023	2022
Benefit obligations as of December 31:						
Discount rate	5.77 %	5.36 %	5.65 %	5.73 %	5.35 %	4.54 %
Rate of compensation increase	3.00 %	3.00 %	3.00 %	N/A	N/A	N/A
Interest crediting rates for cash balance plan						
2022	N/A	N/A	3.25 %	N/A	N/A	N/A
2023	N/A	4.19 %	4.25 %	N/A	N/A	N/A
2024	4.65 %	4.58 %	4.25 %	N/A	N/A	N/A
2025	4.41 %	4.58 %	3.65 %	N/A	N/A	N/A
2026	4.41 %	3.73 %	3.65 %	N/A	N/A	N/A
2027 and beyond	3.99 %	3.73 %	3.65 %	N/A	N/A	N/A
Net periodic benefit cost for the years ended December 31:						
Discount rate	5.36 %	5.65 %	2.98 %	5.35 %	5.58 %	2.95 %
Expected return on plan assets	6.19 %	6.10 %	4.30 %	5.71 %	5.84 %	4.20 %
Rate of compensation increase	3.00 %	3.00 %	2.75 %	N/A	N/A	N/A
Interest crediting rate for cash balance plan	4.65 %	4.19 %	3.25 %	N/A	N/A	N/A

In establishing its assumption as to the expected return on plan assets, the Company utilizes the asset allocation and return assumptions for each asset class based on historical performance and forward-looking views of the financial markets.

	2024	2023
Assumed healthcare cost trend rates as of December 31:		
Healthcare cost trend rate assumed for next year	7.00 %	6.44 %
Rate that the cost trend rate gradually declines to	5.00 %	5.00 %
Year that the rate reaches the rate it is assumed to remain at	2033	2028

Contributions and Benefit Payments

Employer contributions to the pension and other postretirement benefit plans are expected to be \$13 million and \$1 million, respectively, during 2025. Funding to the established pension trusts is based upon the actuarially determined costs of the plans and the requirements of the IRC, the Employee Retirement Income Security Act of 1974 and the Pension Protection Act of 2006, as amended. The Company considers contributing additional amounts from time to time in order to achieve certain funding levels specified under the Pension Protection Act of 2006, as amended. The Company evaluates a variety of factors, including funded status, income tax laws and regulatory requirements, in determining contributions to its other postretirement benefit plans.

The expected benefit payments to participants in the Company's pension and other postretirement benefit plans for 2025 through 2029 and for the five years thereafter are summarized below (in millions):

	Projected Benefit Payments	
	Pension	Other Postretirement
2025	\$ 187	\$ 53
2026	183	53
2027	178	53
2028	171	51
2029	166	49
2030-2034	756	217

Plan Assets

Investment Policy and Asset Allocations

The Company's investment policy for its pension and other postretirement benefit plans is to balance risk and return through a diversified portfolio of debt securities, equity securities and other alternative investments. Maturities for debt securities are managed to targets consistent with prudent risk tolerances. The plans retain outside investment consultants to advise on plan investments within the parameters outlined by the Berkshire Hathaway Energy Company Investment Committee. The investment portfolio is managed in line with the investment policy with sufficient liquidity to meet near-term benefit payments.

The target allocations (percentage of plan assets) for the Company's pension and other postretirement benefit plan assets are as follows as of December 31, 2024:

	Pension	Other
	%	Postretirement
	%	%
PacifiCorp:		
Debt securities ⁽¹⁾	50-80	78-85
Equity securities ⁽¹⁾	10-50	14-20
Limited partnership interests	0-10	1-2
MidAmerican Energy:		
Debt securities ⁽¹⁾	40-60	20-40
Equity securities ⁽¹⁾	30-60	60-80
Other	0-15	0-5
NV Energy:		
Debt securities ⁽¹⁾	65-80	67-88
Equity securities ⁽¹⁾	20-35	12-33

- (1) For purposes of target allocation percentages and consistent with the plans' investment policy, investment funds are allocated based on the underlying investments in debt and equity securities.

Fair Value Measurements

The following table presents the fair value of plan assets, by major category, for the Company's defined benefit pension plans (in millions):

	Input Levels for Fair Value Measurements ⁽¹⁾		
	Level 1	Level 2	Total
As of December 31, 2024:			
Cash equivalents	\$ —	\$ 15	\$ 15
Debt securities:			
U.S. government obligations	156	—	156
Corporate obligations	—	639	639
Municipal obligations	—	33	33
Agency, asset and mortgage-backed obligations	—	103	103
Equity securities:			
U.S. companies	180	—	180
International companies	1	—	1
Total assets in the fair value hierarchy	<u>\$ 337</u>	<u>\$ 790</u>	1,127
Investment funds ⁽²⁾ measured at net asset value			861
Limited partnership interests ⁽³⁾ measured at net asset value			22
Total assets measured at fair value			<u>\$ 2,010</u>
As of December 31, 2023:			
Cash equivalents	\$ —	\$ 40	\$ 40
Debt securities:			
U.S. government obligations	129	—	129
Corporate obligations	—	620	620
Municipal obligations	—	40	40
Agency, asset and mortgage-backed obligations	—	104	104
Equity securities:			
U.S. companies	189	—	189
International companies	1	—	1
Total assets in the fair value hierarchy	<u>\$ 319</u>	<u>\$ 804</u>	1,123
Investment funds ⁽²⁾ measured at net asset value			920
Limited partnership interests ⁽³⁾ measured at net asset value			26
Total assets measured at fair value			<u>\$ 2,069</u>

(1) Refer to Note 15 for additional discussion regarding the three levels of the fair value hierarchy.

(2) Investment funds are comprised of mutual funds and collective trust funds. These funds consist of equity and debt securities of approximately 53% and 47%, respectively, for 2024 and 51% and 49%, respectively, for 2023. Additionally, these funds are invested in U.S. and international securities of approximately 94% and 6%, respectively, for 2024 and 94% and 6%, respectively, for 2023.

(3) Limited partnership interests include several funds that invest primarily in real estate, buyout, growth equity and venture capital.

The following table presents the fair value of plan assets, by major category, for the Company's defined benefit other postretirement plans (in millions):

	Input Levels for Fair Value Measurements ⁽¹⁾		
	Level 1	Level 2	Total
<u>As of December 31, 2024:</u>			
Cash equivalents	\$ 9	\$ 13	\$ 22
Debt securities:			
U.S. government obligations	18	—	18
Corporate obligations	—	37	37
Municipal obligations	—	43	43
Agency, asset and mortgage-backed obligations	—	55	55
Equity securities:			
U.S. companies	7	—	7
Investment funds ⁽²⁾	375	—	375
Total assets in the fair value hierarchy	<u>\$ 409</u>	<u>\$ 148</u>	557
Investment funds ⁽²⁾ measured at net asset value			134
Total assets measured at fair value			<u>\$ 691</u>
<u>As of December 31, 2023:</u>			
Cash equivalents	\$ 13	\$ 9	\$ 22
Debt securities:			
U.S. government obligations	11	—	11
Corporate obligations	—	50	50
Municipal obligations	—	45	45
Agency, asset and mortgage-backed obligations	—	56	56
Equity securities:			
U.S. companies	8	—	8
Investment funds ⁽²⁾	340	—	340
Total assets in the fair value hierarchy	<u>\$ 372</u>	<u>\$ 160</u>	532
Investment funds ⁽²⁾ measured at net asset value			133
Total assets measured at fair value			\$ 665

(1) Refer to Note 15 for additional discussion regarding the three levels of the fair value hierarchy.

(2) Investment funds are comprised of mutual funds and collective trust funds. These funds consist of equity and debt securities of approximately 59% and 41%, respectively, for 2024 and 55% and 45%, respectively, for 2023. Additionally, these funds are invested in U.S. and international securities of approximately 88% and 12%, respectively, for 2024 and 88% and 12%, respectively, for 2023.

For level 1 investments, a readily observable quoted market price or net asset value of an identical security in an active market is used to record the fair value. For level 2 investments, the fair value is determined using pricing models based on observable market inputs. Shares of mutual funds not registered under the Securities Act of 1933, private equity limited partnership interests, common and commingled trust funds and investment entities are reported at fair value based on the net asset value per unit, which is used for expedience purposes. A fund's net asset value is based on the fair value of the underlying assets held by the fund less its liabilities.

Foreign Operations

Certain wholly-owned subsidiaries of Northern Powergrid participate in the Northern Powergrid group of the United Kingdom industry-wide Electricity Supply Pension Scheme (the "UK Plan"), which provides pension and other related defined benefits, based on final pensionable pay, to the employees of Northern Powergrid. The UK Plan is closed to employees hired after July 23, 1997. Employees hired after that date are covered by a defined contribution plan sponsored by a wholly-owned subsidiary of Northern Powergrid.

Net Periodic Benefit Cost (Credit)

For purposes of calculating the expected return on pension plan assets, a market-related value is used. The market-related value of plan assets is calculated by including the difference between expected and actual investment returns after the first year in which they occur.

Net periodic benefit cost (credit) for the UK Plan included the following components for the years ended December 31 (in millions):

	<u>2024</u>	<u>2023</u>	<u>2022</u>
Service cost	\$ 6	\$ 6	\$ 14
Interest cost	54	57	35
Expected return on plan assets	(80)	(80)	(92)
Net amortization	29	26	24
Net periodic benefit cost (credit)	<u>\$ 9</u>	<u>\$ 9</u>	<u>\$ (19)</u>

Funded Status

The following table is a reconciliation of the fair value of plan assets for the years ended December 31 (in millions):

	<u>2024</u>	<u>2023</u>
Plan assets at fair value, beginning of year	\$ 1,402	\$ 1,363
Employer contributions	12	13
Participant contributions	1	1
Actual return on plan assets	(71)	52
Benefits paid	(80)	(97)
Foreign currency exchange rate changes	(22)	70
Plan assets at fair value, end of year	<u>\$ 1,242</u>	<u>\$ 1,402</u>

The following table is a reconciliation of the benefit obligation for the years ended December 31 (in millions):

	<u>2024</u>	<u>2023</u>
Benefit obligation, beginning of year	\$ 1,219	\$ 1,175
Service cost	6	6
Interest cost	54	57
Participant contributions	1	1
Actuarial (gain) loss	(107)	1
Amendment	—	16
Benefits paid	(80)	(97)
Foreign currency exchange rate changes	(19)	60
Benefit obligation, end of year	<u>\$ 1,074</u>	<u>\$ 1,219</u>
Accumulated benefit obligation, end of year	<u>\$ 970</u>	<u>\$ 1,103</u>

The funded status of the UK Plan and the amounts recognized on the Consolidated Balance Sheets as of December 31 are as follows (in millions):

	<u>2024</u>	<u>2023</u>
Plan assets at fair value, end of year	\$ 1,242	\$ 1,402
Benefit obligation, end of year	1,074	1,219
Funded status	<u>\$ 168</u>	<u>\$ 183</u>

Amounts recognized on the Consolidated Balance Sheets:

Other assets	<u>\$ 168</u>	<u>\$ 183</u>

Unrecognized Amounts

The portion of the funded status of the UK Plan not yet recognized in net periodic benefit cost as of December 31 is as follows (in millions):

	<u>2024</u>	<u>2023</u>
Net loss	\$ 541	\$ 532
Prior service cost	40	44
Total	<u>\$ 581</u>	<u>\$ 576</u>

A reconciliation of the amounts not yet recognized as components of net periodic benefit cost, which are included in accumulated other comprehensive loss on the Consolidated Balance Sheets, for the years ended December 31 is as follows (in millions):

	<u>2024</u>	<u>2023</u>
Balance, beginning of year	\$ 576	\$ 529
Net loss arising during the year	44	29
Net prior service cost arising during the year	—	16
Net amortization	(29)	(26)
Foreign currency exchange rate changes	(10)	28
Total	5	47
Balance, end of year	<u>\$ 581</u>	<u>\$ 576</u>

Plan Assumptions

Assumptions used to determine benefit obligations and net periodic benefit cost were as follows:

	2024	2023	2022
Benefit obligations as of December 31:			
Discount rate	5.50 %	4.55 %	4.80 %
Rate of compensation increase	3.30 %	3.00 %	3.20 %
Rate of future price inflation	3.05 %	2.75 %	2.95 %
Net periodic benefit cost for the years ended December 31:			
Discount rate	4.55 %	4.80 %	1.95 %
Expected return on plan assets	5.95 %	6.00 %	4.40 %
Rate of compensation increase	3.00 %	3.20 %	3.45 %
Rate of future price inflation	2.75 %	2.95 %	2.95 %

Contributions and Benefit Payments

Employer contributions to the UK Plan are expected to be £8 million during 2025. The expected benefit payments to participants in the UK Plan for 2025 through 2029 and for the five years thereafter, excluding lump sum settlement elections and using the foreign currency exchange rate as of December 31, 2024, are summarized below (in millions):

2025	\$	81
2026		83
2027		85
2028		87
2029		89
2030-2034		483

Plan Assets

Investment Policy and Asset Allocations

The investment policy for the UK Plan is to balance risk and return through a diversified portfolio of debt securities, equity securities, real estate and other asset classes. Maturities for debt securities are managed to targets consistent with prudent risk tolerances. The UK Plan retains outside investment advisors to manage plan investments within the parameters set by the trustees of the UK Plan in consultation with Northern Powergrid. The investment portfolio is managed in line with the investment policy with sufficient liquidity to meet near-term benefit payments. The return on assets assumption is based on a weighted-average of the expected historical performance for the types of assets in which the UK Plan invests.

The target allocations (percentage of plan assets) for the UK Plan assets are as follows as of December 31, 2024:

	%
Debt securities ⁽¹⁾	60-70
Equity securities ⁽¹⁾	10-20
Real estate funds and other	15-25

- (1) For purposes of target allocation percentages and consistent with the plans' investment policy, investment funds have been allocated based on the underlying investments in debt and equity securities.

Fair Value Measurements

The following table presents the fair value of the UK Plan assets, by major category (in millions):

	Input Levels for Fair Value Measurements ⁽¹⁾			
	Level 1	Level 2	Level 3	Total
As of December 31, 2024:				
Cash equivalents	\$ 1	\$ 22	\$ —	\$ 23
Debt securities:				
United Kingdom government obligations	428	—	—	428
Equity securities:				
Investment funds ⁽²⁾	—	570	—	570
Real estate funds	—	—	134	134
Total	<u>\$ 429</u>	<u>\$ 592</u>	<u>\$ 134</u>	<u>1,155</u>
Investment funds ⁽²⁾ measured at net asset value				87
Total assets measured at fair value				<u>\$ 1,242</u>
As of December 31, 2023:				
Cash equivalents	\$ 8	\$ 28	\$ —	\$ 36
Debt securities:				
United Kingdom government obligations	579	—	—	579
Equity securities:				
Investment funds ⁽²⁾	—	532	—	532
Real estate funds	—	—	136	136
Total	<u>\$ 587</u>	<u>\$ 560</u>	<u>\$ 136</u>	<u>1,283</u>
Investment funds ⁽²⁾ measured at net asset value				119
Total assets measured at fair value				<u>\$ 1,402</u>

(1) Refer to Note 15 for additional discussion regarding the three levels of the fair value hierarchy.

(2) Investment funds are comprised of mutual funds and collective trust funds. These funds consist of equity and debt securities of approximately 10% and 90%, respectively, for 2024 and 14% and 86%, respectively, for 2023.

The fair value of the UK Plan's assets are determined similar to the plan assets of the domestic plans as previously discussed.

The following table reconciles the beginning and ending balances of the UK Plan assets measured at fair value using significant Level 3 inputs for the years ended December 31 (in millions):

	Real Estate Funds		
	2024	2023	2022
Beginning balance	\$ 136	\$ 214	\$ 269
Actual return on plan assets still held at period end	—	(87)	(27)
Foreign currency exchange rate changes	(2)	9	(28)
Ending balance	\$ 134	\$ 136	\$ 214

Defined Contribution Plans

The Company sponsors various defined contribution plans covering substantially all employees. The Company's contributions vary depending on the plan, but matching contributions are based on each participant's level of contribution, and certain participants receive contributions based on eligible pre-tax annual compensation. Contributions cannot exceed the maximum allowable for tax purposes. The Company's contributions to these plans were \$196 million, \$177 million and \$159 million for the years ended December 31, 2024, 2023 and 2022, respectively.

(14) Asset Retirement Obligations

The Company estimates its ARO liabilities based upon detailed engineering calculations of the amount and timing of the future cash spending for a third party to perform the required work. Spending estimates are escalated for inflation and then discounted at a credit-adjusted, risk-free rate. Changes in estimates could occur for a number of reasons, including changes in laws and regulations, plan revisions, inflation and changes in the amount and timing of the expected work.

The Company does not recognize liabilities for AROs for which the fair value cannot be reasonably estimated. Due to the indeterminate removal date, the fair value of the associated liabilities on certain generation, transmission, distribution and other assets cannot currently be estimated, and no amounts are recognized on the Consolidated Financial Statements other than those included in the cost of removal regulatory liability established via approved depreciation rates in accordance with accepted regulatory practices. These accruals totaled \$2.9 billion and \$2.7 billion as of December 31, 2024 and 2023, respectively.

The following table presents the Company's ARO liabilities by asset type as of December 31 (in millions):

	2024	2023
Fossil-fueled generating facilities	\$ 477	\$ 402
Wind-powered generating facilities	471	452
Quad Cities Station	428	407
Solar-powered generating facilities	37	36
Offshore pipeline facilities	15	15
Other	122	116
Total asset retirement obligations	<u>\$ 1,550</u>	<u>\$ 1,428</u>
Quad Cities Station nuclear decommissioning trust funds	<u>\$ 871</u>	<u>\$ 767</u>

The following table reconciles the beginning and ending balances of the Company's ARO liabilities for the years ended December 31 (in millions):

	2024	2023
Beginning balance	\$ 1,428	\$ 1,328
Change in estimated costs	63	54
Additions	39	56
Retirements	(38)	(64)
Accretion	58	54
Ending balance	<u>\$ 1,550</u>	<u>\$ 1,428</u>
Reflected as:		
Other current liabilities	\$ 63	\$ 34
Other long-term liabilities	1,487	1,394
Total ARO liability	<u>\$ 1,550</u>	<u>\$ 1,428</u>

The Nuclear Regulatory Commission regulates the decommissioning of nuclear generating facilities, which includes the planning and funding for the decommissioning. In accordance with these regulations, MidAmerican Energy submits a biennial report to the Nuclear Regulatory Commission providing reasonable assurance that funds will be available to pay for its share of the Quad Cities Station decommissioning.

Certain of the Company's decommissioning and reclamation obligations relate to jointly owned facilities and mine sites, and as such, each subsidiary is committed to pay a proportionate share of the decommissioning or reclamation costs. In the event of a default by any of the other joint participants, the respective subsidiary may be obligated to absorb, directly or by paying additional sums to the entity, a proportionate share of the defaulting party's liability. The Company's estimated share of the decommissioning and reclamation obligations are primarily recorded as ARO liabilities.

In May 2024, the United States Environmental Protection Agency published its final rule on legacy coal combustion residuals ("CCR") surface impoundments and CCR management units ("CCRMUs") in the Federal Register. CCRMUs include CCR surface impoundments and landfills closed before October 19, 2015 and inactive CCR landfills. The final rule contains three main components: (1) a definition for legacy CCR surface impoundments, which are inactive surface impoundments at inactive generating facilities that must adhere to the same regulations as inactive CCR impoundments at active generating facilities, barring location restrictions and liner design criteria, with customized compliance deadlines; (2) groundwater monitoring, corrective action, closure, and post closure care requirements for CCRMUs, which may be located at active generating facilities and inactive generating facilities with a legacy CCR surface impoundment; and (3) the owners and operators of inactive generating facilities must identify the presence of legacy CCR surface impoundments and comply with all rule requirements for surface impoundments; and the owners and operators of active generating facilities and inactive generating facilities with a legacy CCR surface impoundment must prepare Facility Evaluation Reports ("FERs") that identify and describe the CCRMUs and determine whether closure is required. In a manner consistent with existing CCR rules, owners and operators must publish FERs on their CCR websites in two parts, within 15 months (Part 1) and 27 months (Part 2) of the final rule's effective date in November 2024. The Company is currently evaluating the final rule and does not anticipate identifying any legacy surface impoundments, but does anticipate identifying CCRMUs subject to the rule. Due to the number of site investigations warranted by this rule and the nature of engineering and other studies required at each site, the Company is unable to reasonably estimate the potential impact, which may be material, to its asset retirement obligations.

(15) Fair Value Measurements

The carrying value of the Company's cash, certain cash equivalents, receivables, payables, accrued liabilities and short-term borrowings approximates fair value because of the short-term maturity of these instruments. The Company has various financial assets and liabilities that are measured at fair value on the Consolidated Financial Statements using inputs from the three levels of the fair value hierarchy. A financial asset or liability classification within the hierarchy is determined based on the lowest level input that is significant to the fair value measurement. The three levels are as follows:

- Level 1 - Inputs are unadjusted quoted prices in active markets for identical assets or liabilities that the Company has the ability to access at the measurement date.
- Level 2 - Inputs include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived principally from or corroborated by observable market data by correlation or other means (market corroborated inputs).
- Level 3 - Unobservable inputs reflect the Company's judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. The Company develops these inputs based on the best information available, including its own data.

The following table presents the Company's financial assets and liabilities recognized on the Consolidated Balance Sheets and measured at fair value on a recurring basis (in millions):

	Input Levels for Fair Value Measurements					
	Level 1	Level 2	Level 3	Other ⁽¹⁾	Total	
As of December 31, 2024:						
Assets:						
Commodity derivatives	\$ —	\$ 81	\$ 2	\$ (22)	\$ 61	
Interest rate derivatives	33	42	7	—	82	
Mortgage loans held for sale	—	528	—	—	528	
Money market mutual funds	927	—	—	—	927	
Debt securities:						
U.S. government obligations	271	—	—	—	271	
Corporate obligations	—	109	—	—	109	
Municipal obligations	—	2	—	—	2	
Equity securities:						
U.S. companies	479	—	—	—	479	
International companies	424	—	—	—	424	
Investment funds	313	—	—	—	313	
	\$ 2,447	\$ 762	\$ 9	\$ (22)	\$ 3,196	
Liabilities:						
Commodity derivatives	\$ (15)	\$ (141)	\$ (74)	\$ 31	\$ (199)	
Foreign currency exchange rate derivatives	—	(23)	—	—	(23)	
Interest rate derivatives	—	(1)	(2)	—	(3)	
	\$ (15)	\$ (165)	\$ (76)	\$ 31	\$ (225)	

	Input Levels for Fair Value Measurements				
	Level 1	Level 2	Level 3	Other ⁽¹⁾	Total
As of December 31, 2023:					
Assets:					
Commodity derivatives	\$ 1	\$ 121	\$ 4	\$ (31)	\$ 95
Interest rate derivatives	38	40	7	—	85
Mortgage loans held for sale	—	451	—	—	451
Money market mutual funds	1,310	—	—	—	1,310
Debt securities:					
U.S. government obligations	1,253	—	—	—	1,253
Corporate obligations	—	70	—	—	70
Municipal obligations	—	3	—	—	3
Equity securities:					
U.S. companies	427	—	—	—	427
International companies	2,226	—	—	—	2,226
Investment funds	268	—	—	—	268
	<u>\$ 5,523</u>	<u>\$ 685</u>	<u>\$ 11</u>	<u>\$ (31)</u>	<u>\$ 6,188</u>
Liabilities:					
Commodity derivatives	\$ (7)	\$ (134)	\$ (95)	\$ 54	\$ (182)
Foreign currency exchange rate derivatives	—	(8)	—	—	(8)
Interest rate derivatives	—	(7)	—	4	(3)
	<u>\$ (7)</u>	<u>\$ (149)</u>	<u>\$ (95)</u>	<u>\$ 58</u>	<u>\$ (193)</u>

(1) Represents netting under master netting arrangements and a net cash collateral receivable of \$9 million and \$27 million as of December 31, 2024 and 2023, respectively.

Derivative contracts are recorded on the Consolidated Balance Sheets as either assets or liabilities and are stated at estimated fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by GAAP. When available, the fair value of derivative contracts is estimated using unadjusted quoted prices for identical contracts in the market in which the Company transacts. When quoted prices for identical contracts are not available, the Company uses forward price curves. Forward price curves represent the Company's estimates of the prices at which a buyer or seller could contract today for delivery or settlement at future dates. The Company bases its forward price curves upon market price quotations, when available, or internally developed and commercial models, with internal and external fundamental data inputs. Market price quotations are obtained from independent brokers, exchanges, direct communication with market participants and actual transactions executed by the Company. Market price quotations are generally readily obtainable for the applicable term of the Company's outstanding derivative contracts; therefore, the Company's forward price curves reflect observable market quotes. Market price quotations for certain electricity and natural gas trading hubs are not as readily obtainable due to the length of the contract. Given that limited market data exists for these contracts, as well as for those contracts that are not actively traded, the Company uses forward price curves derived from internal models based on perceived pricing relationships to major trading hubs that are based on unobservable inputs. The estimated fair value of these derivative contracts is a function of underlying forward commodity prices, interest rates, currency rates, related volatility, counterparty creditworthiness and duration of contracts.

The Company's mortgage loans held for sale are valued based on independent quoted market prices, where available, or the prices of other mortgage whole loans with similar characteristics. As necessary, these prices are adjusted for typical securitization activities, including servicing value, portfolio composition, market conditions and liquidity.

The Company's investments in money market mutual funds and debt and equity securities are stated at fair value. When available, a readily observable quoted market price or net asset value of an identical security in an active market is used to record the fair value. In the absence of a quoted market price or net asset value of an identical security, the fair value is determined using pricing models or net asset values based on observable market inputs and quoted market prices of securities with similar characteristics.

The following table reconciles the beginning and ending balances of the Company's financial assets and liabilities measured at fair value on a recurring basis using significant Level 3 inputs for the years ended December 31 (in millions). Transfers out of Level 3 occur primarily due to increased price observability.

	Commodity Derivatives			Interest Rate Derivatives		
	2024	2023	2022	2024	2023	2022
Beginning balance	\$ (91)	\$ (59)	\$ (151)	\$ 7	\$ 6	\$ 19
Changes included in earnings ⁽¹⁾	(4)	9	(85)	(2)	1	(13)
Changes in fair value recognized in OCI	—	(3)	9	—	—	—
Changes in fair value recognized in net regulatory assets	(135)	(256)	(52)	—	—	—
Purchases	—	2	3	—	—	—
Settlements	158	216	171	—	—	—
Transfers out of Level 3 into Level 2	—	—	46	—	—	—
Ending balance	<u>\$ (72)</u>	<u>\$ (91)</u>	<u>\$ (59)</u>	<u>\$ 5</u>	<u>\$ 7</u>	<u>\$ 6</u>

(1) Changes included in earnings for interest rate derivatives are reported net of amounts related to the satisfaction of the associated loan commitment.

The Company's long-term debt is carried at cost, including fair value adjustments and unamortized premiums, discounts and debt issuance costs as applicable, on the Consolidated Financial Statements. The fair value of the Company's long-term debt is a Level 2 fair value measurement and has been estimated based upon quoted market prices, where available, or at the present value of future cash flows discounted at rates consistent with comparable maturities with similar credit risks. The carrying value of the Company's variable-rate long-term debt approximates fair value because of the frequent repricing of these instruments at market rates. The following table presents the carrying value and estimated fair value of the Company's long-term debt as of December 31 (in millions):

	2024		2023	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	<u>\$ 55,257</u>	<u>\$ 50,179</u>	<u>\$ 52,172</u>	<u>\$ 48,624</u>

(16) Commitments and Contingencies

Commitments

The Company has the following firm commitments that are not reflected on the Consolidated Balance Sheet. Minimum payments as of December 31, 2024 are as follows (in millions):

	2025	2026	2027	2028	2029	2030 and Thereafter	Total
Contract type:							
Fuel, capacity and transmission contract commitments	\$ 2,391	\$ 1,880	\$ 1,842	\$ 1,795	\$ 1,753	\$ 17,409	\$ 27,070
Construction commitments	3,300	1,610	838	295	66	30	6,139
Easements	85	88	90	91	91	3,105	3,550
Maintenance, service and other contracts	446	430	363	270	218	918	2,645
	<u>\$ 6,222</u>	<u>\$ 4,008</u>	<u>\$ 3,133</u>	<u>\$ 2,451</u>	<u>\$ 2,128</u>	<u>\$ 21,462</u>	<u>\$ 39,404</u>

Fuel, Capacity and Transmission Contract Commitments

The Utilities have fuel supply and related transportation and lime contracts for their coal- and natural gas-fueled generating facilities. The Utilities expect to supplement these contracts with additional contracts and spot market purchases to fulfill their future fossil fuel needs. The Utilities acquire a portion of their electricity through long-term purchases and exchange agreements. The Utilities have several power purchase agreements with renewable generating facilities that are not included in the table above as the payments are based on the amount of energy generated and there are no minimum payments. The Utilities also have contracts for the right to transmit electricity over other entities' transmission lines to facilitate delivery to their customers.

MidAmerican Energy has long-term rail transportation contracts with BNSF Railway Company ("BNSF"), an affiliate company, and Union Pacific Railroad Company for the transportation of coal to all of the MidAmerican Energy-operated coal-fueled generating facilities. For the years ended December 31, 2024, 2023 and 2022, \$80 million, \$109 million and \$100 million, respectively, were incurred for coal transportation services, the majority of which was related to the BNSF and Union Pacific Railway Company agreements.

Construction Commitments

The Company's firm construction commitments reflected in the table above include the following major construction projects:

- PacifiCorp's costs associated with certain generating plant, transmission, and distribution projects.
- MidAmerican Energy's firm construction commitments primarily consisting of contracts for the repowering of wind-powered generating facilities, construction of new generating facilities, and the settlement of AROs.
- Nevada Utilities' firm construction commitments consisting of costs associated with a 400-MW solar photovoltaic facility with an additional 400-MWs of co-located battery storage that is being developed in Churchill County, Nevada, with ownership share approved by the PUCN of 10% Nevada Power and 90% Sierra Pacific, the Greenlink Nevada transmission expansion program that is being developed in western and northern Nevada, the repower project at the Valmy generating station to convert existing coal-fired combustion to natural gas-fire combustion, a hydrogen-capable natural gas simple cycle combustion turbine peakers project at the Valmy generating station and certain other generation plant projects.
- AltaLink's investments in directly assigned transmission projects from the Alberta Electric System Operator.

Easements

The Company has non-cancelable easements for land on which certain of its assets, primarily wind- and solar-powered generating facilities, are located.

Maintenance, Service and Other Contracts

The Company has entered into service agreements related to its nonregulated wind-powered and solar-powered projects with third parties to operate and maintain the projects under fixed-fee operating and maintenance agreements. Additionally, the Company has various non-cancelable maintenance, service and other contracts primarily related to turbine and equipment maintenance and various other service agreements.

Environmental Laws and Regulations

The Company is subject to federal, state, local and foreign laws and regulations regarding air quality, climate change, emissions performance standards, water quality, coal ash disposal and other environmental matters that have the potential to impact its current and future operations. The Company believes it is in material compliance with all applicable laws and regulations.

Lower Klamath Hydroelectric Project

PacifiCorp is a party to the 2016 amended Klamath Hydroelectric Settlement Agreement ("KHSA"), which addressed disputes surrounding PacifiCorp's efforts to relicense the Klamath Hydroelectric Project. The KHSA established a process for PacifiCorp, the states of Oregon and California ("States") and other stakeholders to assess whether dam removal could occur consistent with the settlement's terms. For PacifiCorp, the key elements of the settlement include: (1) a contribution from PacifiCorp's Oregon and California customers capped at \$200 million plus \$250 million in California bond funds; (2) complete indemnification from harms associated with dam removal; (3) transfer of the Federal Energy Regulatory Commission ("FERC") license to a third-party dam removal entity, the Klamath River Renewal Corporation ("KRRC"); and (4) ability for PacifiCorp to operate the facilities for the benefit of customers through commencement of dam removal.

In September 2016, the KRRC and PacifiCorp filed a joint application with the FERC to transfer the license for the four mainstem Klamath hydroelectric dams comprising the Lower Klamath Project (FERC Project No. 14803) from PacifiCorp to the KRRC. The KRRC filed an amended license surrender application for the Lower Klamath Project with FERC in November 2020. In November 2022, the FERC issued a license surrender order for the Lower Klamath Project, which was accepted by the KRRC and the States in December 2022, resulting in the transfer of the Lower Klamath Project dams. Although PacifiCorp no longer owned the Lower Klamath Project, PacifiCorp continued to operate the facilities under an operation and maintenance agreement with the KRRC until each facility was ready for removal. PacifiCorp's obligations under the operations and maintenance agreement terminated in January 2024, when PacifiCorp's customers no longer received generation benefits from the facilities. Removal of the Copco No. 2 facility was completed in November 2023, and removal of the remaining three dams (J.C. Boyle, Copco No. 1, and Iron Gate) was completed in October 2024. The KRRC has \$450 million in funding available for dam removal and restoration; \$200 million collected from PacifiCorp's Oregon and California customers and \$250 million in California bond funds. PacifiCorp and the States have also agreed to equally share cost overruns that may occur above the initial \$450 million in funding. Specifically, PacifiCorp and the States have agreed to equally fund an initial \$45 million supplemental fund and equally share any additional costs above that amount to ensure dam removal and restoration is complete. In May 2024, the KRRC communicated to PacifiCorp and the States that it expects to require the \$45 million of supplemental funds. In October 2024, PacifiCorp provided approximately \$11 million in supplemental funding to the KRRC.

Hydroelectric Commitments

Certain of PacifiCorp's hydroelectric licenses and settlement agreements contain requirements for PacifiCorp to make certain capital and operating expenditures related to its hydroelectric facilities, which are estimated to be approximately \$333 million over the next 10 years.

Legal Matters

The Company is party to a variety of legal actions, including litigation, arising out of the normal course of business, some of which assert claims for damages in substantial amounts and are described below. For certain legal actions, parties at times may seek to impose fines, penalties and other costs.

Pursuant to ASC 450, "Contingencies," a provision for a loss contingency is recorded when it is probable a liability is likely to occur and the amount of loss can be reasonably estimated. The Company evaluates the related range of reasonably estimated losses and records a loss based on its best estimate within that range or the lower end of the range if there is no better estimate.

Wildfires

As of the date of this filing, a significant number of complaints and demands alleging similar claims related to the Wildfires have been filed in Oregon and California, including a class action complaint in Oregon associated with 2020 Wildfires for which certain jury verdicts were issued as described below. The plaintiffs seek damages for economic losses, noneconomic losses, including mental suffering, emotional distress, personal injury and loss of life, punitive damages, other damages and attorneys' fees. Several insurance carriers have filed subrogation complaints in Oregon and California with allegations similar to those made in the aforementioned complaints. Additionally, PacifiCorp received correspondence from the U.S. and Oregon Departments of Justice regarding the potential recovery of certain costs and damages alleged to have occurred on federal and state lands in connection with certain of the Oregon 2020 Wildfires. In December 2024, the United States of America filed a complaint against PacifiCorp in conjunction with the correspondence from the U.S. Department of Justice. The civil cover sheet accompanying the complaint demands damages estimated to exceed \$900 million. PacifiCorp is actively cooperating with the U.S. and Oregon Departments of Justice on resolving these alleged claims.

Amounts sought in outstanding complaints and demands filed in Oregon and in certain demands made in California totaled approximately \$3 billion, excluding any doubling or trebling of damages included in the complaints and the mass complaints described below that seek \$48 billion. Generally, the complaints filed in California do not specify damages sought and are excluded from this amount. For class actions, amounts specified by the plaintiffs in the complaints include amounts based on estimates of the potential class size, which ultimately may be significantly greater than estimated. Additionally, damages are not limited to the amounts specified in the initially filed complaints as plaintiffs are frequently allowed to amend their complaints to add additional damages and amounts awarded in a court proceeding may be significantly greater than the damages specified. Oregon law provides for doubling of economic and property damages in the event the defendant is found to have acted with gross negligence, recklessness, willfulness or malice. Oregon law provides for trebling of the damages associated with timber, shrubs and produce in the event the defendant is determined to have willfully and intentionally trespassed.

In California, under inverse condemnation, courts have held that investor-owned utilities can be liable for real and personal property damages from wildfires without the utility being found negligent and regardless of fault. California law also permits inverse condemnation plaintiffs to recover reasonable attorney fees and costs. In both Oregon and California, PacifiCorp has equipment in areas accessed through special use permits, easements or similar agreements that may contain provisions requiring it to pay for damages caused by its equipment regardless of fault. Even if inverse condemnation or other provisions do not apply, PacifiCorp could be found liable for all damages.

Based on available information to date, PacifiCorp believes it is probable that losses will be incurred associated with the Wildfires. Final determinations of liability will only be made following the completion of comprehensive investigations, litigation or similar processes, the outcome of which, if adverse, could, in the aggregate, have a material adverse effect on PacifiCorp's financial condition.

2020 Wildfires

In September 2020, a severe weather event resulting in high winds, low humidity and warm temperatures contributed to several major wildfires, which resulted in real and personal property and natural resource damage, personal injuries and loss of life, and widespread power outages in Oregon and Northern California. The wildfires spread across certain parts of PacifiCorp's service territory and surrounding areas across multiple counties in Oregon and California, including Siskiyou County, California; Jackson County, Oregon; Douglas County, Oregon; Marion County, Oregon; Lincoln County, Oregon; and Klamath County, Oregon, burning over 500,000 acres in aggregate. Third-party reports for these wildfires indicate over 2,000 structures destroyed, including residences; several structures damaged; multiple individuals injured; and several fatalities.

Investigations into the cause and origin of each wildfire are complex and ongoing and have been or are being conducted by various entities, including the U.S. Forest Service, the California Public Utilities Commission, the Oregon Department of Forestry, the Oregon Department of Justice, PacifiCorp and various experts engaged by PacifiCorp.

The James Case

On September 30, 2020, a class action complaint against PacifiCorp was filed, captioned *Jeanyne James et al. v. PacifiCorp*, ("James") in Oregon Circuit Court in Multnomah County, Oregon ("*Multnomah County Circuit Court Oregon*"). The complaint was filed by Oregon residents and businesses who seek to represent a class of all Oregon citizens and entities whose real or personal property was harmed beginning on September 7, 2020, by wildfires in Oregon allegedly caused by PacifiCorp. In November 2021, the plaintiffs filed an amended complaint to limit the class to include Oregon citizens allegedly impacted by the Santiam Canyon, Echo Mountain Complex, South Obenchain and 242 wildfires. In May 2022, the Multnomah County Circuit Court Oregon granted issue class certification and consolidated the *James* case with several other cases. While PacifiCorp's pre-trial request for immediate appeal of the class certification was denied, it subsequently filed to appeal the class issues as described below.

In April 2023, the jury trial for *James* with respect to 17 named plaintiffs began in Multnomah County Circuit Court Oregon. In June 2023, the jury issued its verdict finding PacifiCorp liable to the 17 named plaintiffs and to the class with respect to the four wildfires. The jury found PacifiCorp's conduct grossly negligent, reckless and willful as to each plaintiff and the entire class. The jury awarded the 17 named plaintiffs \$90 million of damages, including \$4 million of economic damages, \$68 million of noneconomic damages and \$18 million of punitive damages based on a 0.25 multiplier of the economic and noneconomic damages.

In September 2023, the Multnomah County Circuit Court Oregon ordered trial dates for three damages phase trials described below wherein plaintiffs in each of the three damages phase trials would present evidence regarding their damages.

In January 2024, the Multnomah County Circuit Court Oregon entered a limited judgment and money award for the June 2023 *James* verdict. The limited judgment awards \$92 million of damages based on the amounts awarded by the jury, as well as doubling of the economic damages and offsetting of any insurance proceeds received by plaintiffs. The limited judgment created a lien against PacifiCorp, attaching a debt for the money awards. PacifiCorp posted a supersedeas bond, which stays any effort to seek payment of the judgment pending final resolution of any appeals. Under Oregon Revised Statutes 82.010, interest at a rate of 9% per annum will accrue on the judgment commencing at the date the judgment was entered until the entire money award is paid, amended or reversed by an appellate court. In January 2024, PacifiCorp filed a notice of appeal associated with the June 2023 verdict in *James*, including whether the case can proceed as a class action and filed a motion to stay further damages phase trials. On February 14, 2024, the Oregon Court of Appeals denied PacifiCorp's request to stay the damages phase trials. On February 13, 2024, the 17 named plaintiffs filed a notice of cross-appeal as to the January 2024 limited judgment and money award. The appeals process and further actions could take several years.

In January 2024, the jury for the first *James* damages phase trial awarded nine plaintiffs \$62 million of damages, including \$6 million of economic damages and \$56 million of noneconomic damages. After the jury verdict, the Multnomah County Circuit Court Oregon doubled the economic damages to \$12 million and added \$16 million of punitive damages using the 0.25 multiplier determined by the jury for the June 2023 *James* verdict, bringing the total damages awarded to \$84 million. PacifiCorp requested that the Multnomah County Circuit Court Oregon judge offset the damage awards by deducting insurance proceeds received by any of the nine plaintiffs, and on March 25, 2024, the Multnomah County Circuit Court Oregon granted in large part the offset request. In April 2024, the Multnomah County Circuit Court Oregon entered a limited judgment and money award for the January 2024 *James* verdict. The limited judgment awards \$80 million of damages based on the amounts awarded by the jury and offsetting insurance proceeds received by plaintiffs. The limited judgment created a lien against PacifiCorp, attaching a debt for the money awards. In April 2024, PacifiCorp posted a supersedeas bond, which stays any effort to seek payment of the judgment pending final resolution of any appeals. PacifiCorp amended its January 2024 appeal of the June 2023 *James* verdict to include the January 2024 jury verdict.

In March 2024, the jury for the second *James* damages phase trial awarded ten plaintiffs \$42 million of damages, including \$12 million of doubled economic damages, \$23 million of noneconomic damages and \$7 million of punitive damages using the 0.25 multiplier determined by the jury for the June 2023 *James* verdict. PacifiCorp requested that the Multnomah County Circuit Court Oregon judge offset the damage awards by deducting insurance proceeds received by any of the ten plaintiffs and on May 6, 2024, the Multnomah County Circuit Court Oregon granted the offset request. In June 2024, the Multnomah County Circuit Court Oregon entered a limited judgment and money award for the March 2024 *James* verdict. The limited judgment awards \$38 million of damages based on the amounts awarded by the jury and offsetting insurance proceeds received by plaintiffs. The limited judgment created a lien against PacifiCorp, attaching a debt for the money awards. In July 2024, PacifiCorp posted a supersedeas bond, which stays any effort to seek payment of the judgment pending final resolution of any appeals. PacifiCorp further amended its appeal of the June 2023 *James* verdict to include the March 2024 jury verdict.

PacifiCorp's opening brief is due to be filed with the Oregon Court of Appeals on or before February 25, 2025, in connection with its appeal of the June 2023 *James* verdict and the January and March 2024 verdicts for the first two *James damages phase trials*.

In February 2025, the jury for the third *James* damages phase trial awarded seven plaintiffs \$32 million of noneconomic damages in addition to \$4 million of economic damages stipulated for eight plaintiffs prior to the trial. In accordance with Oregon law, plaintiffs asked the court to double the economic damages to \$8 million after the verdict. PacifiCorp expects the court will award the doubling of economic damages and also increase the award for \$9 million in punitive damages by applying the 0.25 multiplier of economic and noneconomic damages consistent with the June 2023 *James* verdict. As a result, PacifiCorp expects the total award for the eight plaintiffs to be approximately \$49 million. PacifiCorp filed post-trial motions with the Multnomah County Circuit Court Oregon requesting the court offset the damage awards by deducting insurance proceeds received by any of the eight plaintiffs. PacifiCorp intends to appeal the jury's damage awards associated with the February 2025 jury verdict once judgment is entered.

In March 2024, settlement was reached with five commercial timber plaintiffs in the *James* consolidated cases, and the jury trial scheduled for April 2024 was cancelled.

In April, May, July and September 2024, and January 2025, six separate mass complaints against PacifiCorp naming 1,591 individual class members were filed in Multnomah County Circuit Court Oregon referencing *James* as the lead case. Complaints for five of the plaintiffs in the mass complaints were subsequently dismissed. These *James* mass complaints make damages-only allegations seeking economic, noneconomic and punitive damages, as well as doubling of economic damages. In December 2024, two additional complaints were filed in Multnomah County Circuit Court Oregon on behalf of eight plaintiffs also referencing *James* as the lead case. PacifiCorp believes the magnitude of damages sought by the class members in the *James* mass complaints and additional two complaints to be of remote likelihood of being awarded based on the amounts awarded in the jury verdicts described above that are being appealed.

In October 2024, the Multnomah County Circuit Court Oregon issued a case management order, which sets forth nine additional damages phase trials with up to 10 plaintiffs per trial. The trials are scheduled to begin February 3, March 24, April 21, May 12, June 2, July 7, September 9, October 6 and December 7, 2025. The verdict for the trial that began February 3, 2025, was issued in February 2025 as described above.

2022 McKinney Fire

According to the California Department of Forestry and Fire Protection, a wildfire began on July 29, 2022, in the Oak Knoll Ranger District of the Klamath National Forest in Siskiyou County, California located in PacifiCorp's service territory, burning over 60,000 acres. Third-party reports indicate that the 2022 McKinney Fire resulted in 11 structures damaged; 185 structures destroyed, including residences; 12 injuries; and four fatalities. The U.S. Forest Service issued a Wildland Fire Origin and Cause Supplemental Incident Report. The report concluded that a tree coming in contact with a power line is the probable cause of the 2022 McKinney Fire.

Estimated Losses for and Settlements Associated with the Wildfires

Based on the facts and circumstances available to PacifiCorp as of the date of this filing, including (i) ongoing cause and origin investigations; (ii) ongoing settlement and mediation discussions; (iii) other litigation matters and upcoming legal proceedings; and (iv) the status of the *James* case, PacifiCorp recorded cumulative estimated probable losses associated with the Wildfires of \$2,753 million through December 31, 2024. PacifiCorp's cumulative accrual includes estimates of probable losses for fire suppression costs, real and personal property damages, natural resource damages and noneconomic damages such as personal injury damages and loss of life damages that it is reasonably able to estimate at this time and which is subject to change as additional relevant information becomes available.

Through December 31, 2024, PacifiCorp paid \$1,217 million in settlements associated with the Wildfires. As a result of the settlements, various trials have been cancelled.

The following table presents changes in PacifiCorp's liability for estimated losses associated with the Wildfires for the years ended December 31 (in millions):

	2024	2023	2022
Beginning balance	\$ 1,723	\$ 424	\$ 252
Accrued losses	346	1,930	225
Payments	(533)	(631)	(53)
Ending balance	<u>\$ 1,536</u>	<u>\$ 1,723</u>	<u>\$ 424</u>

As of December 31, 2024 and 2023, \$247 million and \$4 million of PacifiCorp's liability for estimated losses associated with the Wildfires was included in Other current liabilities on the Consolidated Balance Sheets. The amounts reflected as current as of December 31, 2024 reflect amounts reasonably expected to be paid out within the next year based on settlements reached as well as ongoing settlement and mediation efforts. The remainder of PacifiCorp's liability for estimated losses associated with the Wildfires as of December 31, 2024 and 2023 was included in Other long-term liabilities on the Consolidated Balance Sheets. In January and February 2025, PacifiCorp made additional settlement payments related to the Wildfires totaling \$114 million.

The following table presents changes in PacifiCorp's receivable for expected insurance recoveries associated with the Wildfires for the years ended December 31 (in millions):

	2024	2023	2022
Beginning balance	\$ 499	\$ 246	\$ 116
Accruals	—	253	161
Payments received	(401)	—	(31)
Ending balance	<u>\$ 98</u>	<u>\$ 499</u>	<u>\$ 246</u>

As of December 31, 2024, PacifiCorp's receivable for expected insurance recoveries was included in Other current assets on the Consolidated Balance Sheets. As of December 31, 2023, \$350 million of PacifiCorp's receivable for expected insurance recoveries was included in Other current assets while the remaining \$149 million was included in Other assets on the Consolidated Balance Sheets. In January and February 2025, PacifiCorp received insurance proceeds associated with the Wildfires totaling \$28 million.

During the years ended December 31, 2024, 2023 and 2022, PacifiCorp recognized probable losses net of expected insurance recoveries associated with the Wildfires of \$346 million, \$1,677 million and \$64 million, respectively. No additional insurance recoveries beyond those accrued and received to date are expected to be available.

It is reasonably possible PacifiCorp will incur material additional losses beyond the amounts accrued for the Wildfires that could have a material adverse effect on PacifiCorp's financial condition. PacifiCorp is currently unable to reasonably estimate a specific range of possible additional losses that could be incurred due to the number of properties and parties involved, including claimants in the class to the *James* case and the 2022 McKinney Fire, the variation in the types of properties and damages and the ultimate outcome of legal actions, including mediation, settlement negotiations, jury verdicts and the appeals process.

HomeServices Antitrust Cases

HomeServices is currently defending against several antitrust cases, all in federal district courts. In each case, plaintiffs claim HomeServices and certain of its subsidiaries (in one instance, HomeServices and BHE) conspired with co-defendants to artificially inflate real estate commissions by following and enforcing multiple listing service ("MLS") rules that require listing agents to offer a commission split to cooperating agents in order for the property to appear on the MLS ("Cooperative Compensation Rule"). None of the complaints specify damages sought. However, two cases allege Texas state law deceptive trade practices claims, for which plaintiffs have asserted damages totaling approximately \$9 billion by separate written notice as required by Texas law.

In April 2019, the *Burnett (formerly Sitzer) et al. v. HomeServices of America, Inc. et al.* complaint was filed in the U.S. District Court for the Western District of Missouri (the "Burnett case"). This lawsuit, which was certified as a class in April 2022, was originally brought on behalf of named plaintiffs Joshua Sitzer and Amy Winger against the National Association of Realtors ("NAR"), Anywhere Real Estate, HomeServices of America, Inc., RE/MAX, LLC, and Keller Williams Realty, Inc. HSF Affiliates LLC and BHH Affiliates, LLC, each a subsidiary of HomeServices, were subsequently added as defendants. Rhonda Burnett became a lead class plaintiff in June 2021. The jury trial commenced on October 16, 2023, and the jury returned a verdict for the plaintiffs on October 31, 2023, finding that the named defendants participated in a conspiracy to follow and enforce the Cooperative Compensation Rule, which conspiracy had the purpose or effect of raising, inflating, or stabilizing broker commission rates paid by home sellers. The jury further found that the class plaintiffs had proved damages in the amount of \$1.8 billion. Joint and several liability applies for the co-defendants. Federal law authorizes trebling of damages and the award of pre-judgment interest and attorney fees. Prior to the trial, Anywhere Real Estate and RE/MAX, LLC reached settlement agreements with the plaintiffs. Subsequent to the trial, settlements were reached by Keller Williams, NAR and HomeServices on February 1, 2024, March 15, 2024, and April 25, 2024, respectively. The Anywhere Real Estate, RE/MAX, LLC and Keller Williams settlements received final court approval on May 9, 2024, which has been appealed to the U.S. Court of Appeals for the Eighth Circuit. The NAR and HomeServices settlements received final court approval on November 27, 2024, which also has been appealed to the U.S. Court of Appeals for the Eighth Circuit. The U.S. District Court for the Western District of Missouri entered final judgment on the NAR and HomeServices settlements on January 15, 2025.

The final HomeServices settlement agreement with the plaintiffs settles all claims asserted against HomeServices, HSF Affiliates LLC and BHH Affiliates, LLC in the Burnett case and effectuates a nationwide class settlement. The final settlement agreement includes scheduled payments over the next four years aggregating \$250 million. HomeServices recognized an after-tax charge of approximately \$140 million in the first quarter of 2024. If the settlement is not affirmed by the U.S. Court of Appeals for the Eighth Circuit, HomeServices intends to vigorously appeal on multiple grounds the jury's findings and damage award in the Burnett case, including whether the case can proceed as a class action. The appeals process and further actions could take several years.

Guarantees

The Company has entered into guarantees as part of the normal course of business and the sale or transfer of certain assets. These guarantees are not expected to have a material impact on the Company's consolidated financial results.

(17) Revenue from Contracts with Customers

Energy Products and Services

The following table summarizes the Company's energy products and services Customer Revenue by regulated energy and nonregulated energy, with further disaggregation of regulated energy by line of business, including a reconciliation to the Company's reportable segment information included in Note 22, for the years ended December 31 (in millions):

	2024								
	PacifiCorp	MidAmerican Funding	NV Energy	Northern Powergrid	BHE Pipeline Group	BHE Transmission	BHE Renewables	BHE and Other⁽¹⁾	Total
Customer Revenue:									
Regulated:									
Retail Electric	\$ 6,162	\$ 2,287	\$ 3,813	\$ —	\$ —	\$ —	\$ —	\$ (3)	\$ 12,259
Retail Gas	—	604	181	—	—	—	—	—	785
Wholesale	80	221	54	—	7	—	—	(1)	361
Transmission and distribution	176	53	80	1,368	—	674	—	—	2,351
Interstate pipeline	—	—	—	—	2,703	—	—	(130)	2,573
Other	121	—	1	—	4	—	—	—	126
Total Regulated	6,539	3,165	4,129	1,368	2,714	674	—	(134)	18,455
Nonregulated	—	9	6	134	1,042	124	1,273	(4)	2,584
Total Customer Revenue	6,539	3,174	4,135	1,502	3,756	798	1,273	(138)	21,039
Other revenue	61	77	5	125	54	3	202	—	527
Total	<u>\$ 6,600</u>	<u>\$ 3,251</u>	<u>\$ 4,140</u>	<u>\$ 1,627</u>	<u>\$ 3,810</u>	<u>\$ 801</u>	<u>\$ 1,475</u>	<u>\$ (138)</u>	<u>\$ 21,566</u>

2023									
	PacifiCorp	MidAmerican Funding	NV Energy	Northern Powergrid	BHE Pipeline Group	BHE Transmission	BHE Renewables	BHE and Other ⁽¹⁾	Total
Customer Revenue:									
Regulated:									
Retail Electric	\$ 5,462	\$ 2,309	\$ 4,121	\$ —	\$ —	\$ —	\$ —	\$ (1)	\$ 11,891
Retail Gas	—	638	235	—	—	—	—	—	873
Wholesale	165	303	64	—	22	—	—	(1)	553
Transmission and distribution	151	54	77	1,041	—	660	—	—	1,983
Interstate pipeline	—	—	—	—	2,700	—	—	(155)	2,545
Other	129	—	2	—	5	—	—	—	136
Total Regulated	5,907	3,304	4,499	1,041	2,727	660	—	(157)	17,981
Nonregulated	—	7	4	142	984	142	1,436	(1)	2,714
Total Customer Revenue	5,907	3,311	4,503	1,183	3,711	802	1,436	(158)	20,695
Other revenue	29	82	20	120	63	(3)	274	—	585
Total	\$ 5,936	\$ 3,393	\$ 4,523	\$ 1,303	\$ 3,774	\$ 799	\$ 1,710	\$ (158)	\$ 21,280

2022									
	PacifiCorp	MidAmerican Funding	NV Energy	Northern Powergrid	BHE Pipeline Group	BHE Transmission	BHE Renewables	BHE and Other ⁽¹⁾	Total
Customer Revenue:									
Regulated:									
Retail Electric	\$5,099	\$2,320	\$3,465	\$—	\$—	\$—	\$—	\$—	\$10,884
Retail Gas	—	855	167	—	—	—	—	—	1,022
Wholesale	260	668	92	—	8	—	—	(4)	1,024
Transmission and distribution	166	61	76	1,081	—	683	—	—	2,067
Interstate pipeline	—	—	—	—	2,603	—	—	(127)	2,476
Other	102	—	2	—	3	—	—	(2)	105
Total Regulated	5,627	3,904	3,802	1,081	2,614	683	—	(133)	17,578
Nonregulated	—	7	—	169	1,076	70	1,465	(2)	2,785
Total Customer Revenue	5,627	3,911	3,802	1,250	3,690	753	1,465	(135)	20,363
Other revenue	52	114	22	115	154	(21)	272	(2)	706
Total	\$5,679	\$4,025	\$3,824	\$1,365	\$3,844	\$732	\$1,737	\$(137)	\$21,069

(1) The BHE and Other reportable segment represents amounts related principally to other corporate entities, corporate functions and intersegment eliminations.

Real Estate Services

The following table summarizes the Company's real estate services Customer Revenue by line of business for the years ended December 31 (in millions):

	HomeServices		
	2024	2023	2022
Customer Revenue:			
Brokerage	\$ 4,006	\$ 4,000	\$ 4,867
Franchise	53	55	66
Total Customer Revenue	4,059	4,055	4,933
Mortgage and other revenue	295	267	335
Total	\$ 4,354	\$ 4,322	\$ 5,268

Remaining Performance Obligations

The following table summarizes the Company's revenue it expects to recognize in future periods related to significant unsatisfied remaining performance obligations for fixed contracts with expected durations in excess of one year as of December 31, 2024, by reportable segment (in millions):

	Performance obligations expected to be satisfied		Total
	Less than 12 months	More than 12 months	
BHE Pipeline Group	\$ 3,061	\$ 18,958	\$ 22,019
BHE Transmission	655	—	655
Total	\$ 3,716	\$ 18,958	\$ 22,674

(18) BHE Shareholders' Equity

Preferred Stock

As of December 31, 2024, BHE had 481,000 shares outstanding of its Perpetual Preferred Stock (the "4% Perpetual Preferred Stock"), which were issued to a subsidiary of Berkshire Hathaway. The 4% Perpetual Preferred Stock has a liquidation preference of \$1,000 per share and currently pays a 4.00% dividend per share on the liquidation preference. Dividends shall accrue and accumulated daily, be cumulative, compounded semi-annually and, if declared, be payable in cash semi-annually in arrears on May 15 and November 15 of each year. If dividends are not declared and paid, any accumulating dividends shall continue to accumulate and compound. BHE may not make any dividends on shares of any other class or series of its capital stock (other than for dividends on shares of common stock payable in shares of common stock, unless the holders of the then outstanding 4% Perpetual Preferred Stock shall first receive, or simultaneously receive, a dividend in an amount at least equivalent to the amount accumulated and not previously paid. BHE may not declare or pay any dividends on shares of the 4% Perpetual Preferred Stock if such declaration or payment would constitute an event of default on BHE's senior indebtedness (as defined). BHE may, at its option, redeem the 4% Perpetual Preferred Stock in whole or in part at any time at a price per share equal to the liquidation preference.

Common Stock

In December 2024, BHE filed its Fourth Amended and Restated Articles of Incorporation with the Secretary of the State of Iowa, which, among other things, reverse split all of the issued and then-outstanding shares of Common Stock of BHE, no par value (the "Common Stock"), in the aggregate, into one share of the Common Stock and reduced the number of authorized shares of the Common Stock to 100.

In September 2024, BHE repurchased 4,424,494 shares of its voting common stock held by certain family members and related or affiliated entities of the late Mr. Walter Scott, Jr., a former member of BHE's Board of Directors (each, a "Minority Shareholder") and acquired, cancelled and extinguished the Junior Subordinated Debenture due 2057, having an aggregate principal amount of \$100 million, issued by BHE to a certain Minority Shareholder on June 19, 2017 (the "Debenture") (collectively, the "Transactions"). Consideration for the Transactions consisted of (i) cash in an aggregate amount of \$2.4 billion and (ii) a Promissory Note, due and payable on September 30, 2025, having an aggregate principal amount of \$600 million, which was fully repaid plus accrued interest in October 2024.

In June 2022, BHE repurchased 740,961 shares of its common stock held by Mr. Gregory E. Abel, BHE's Chair, for \$870 million. The purchase was pursuant to the terms of BHE's Shareholders Agreement.

BHE B Merger

In December 2024, BHE entered into an agreement and plan of merger ("Merger Agreement") with BHE B, a wholly owned subsidiary of Berkshire Hathaway. BHE B (the "Disappearing Company") merged with and into BHE with BHE surviving (the "Merger"). The Merger was accounted for at book value as BHE and BHE B are entities under common control. BHE B owned eight investments in wind-powered generating facilities sponsored by third parties, commonly referred to as tax equity investments, and had net assets as of December 31, 2024, of approximately \$1 billion.

Pursuant to the terms and conditions in the Merger Agreement, at the effective time of the Merger, which took place at 10:59 p.m., Central Time, on December 31, 2024, (a) the separate existence of the Disappearing Company ceased and each share of Common Stock, \$0.0001 par value, of the Disappearing Company was cancelled and (b) all shares of the issued and outstanding Preferred Stock, \$0.01 par value, of the Disappearing Company, which were held by the BHE B Sole Preferred Stockholder, were converted into and became exchangeable in the aggregate for (i) 481,000 shares of the 4% Perpetual Preferred Stock, (ii) an amount in cash of \$57 million and (iii) the transfer of a U.S. Treasury Bill of \$364 million.

Restricted Net Assets

BHE has maximum debt-to-total capitalization percentage restrictions imposed by its senior unsecured credit facilities expiring in June 2027 which, in certain circumstances, limit BHE's ability to make cash dividends or distributions. As a result of this restriction, BHE has restricted net assets of \$23.3 billion as of December 31, 2024.

Certain of BHE's subsidiaries have restrictions on their ability to dividend, loan or advance funds to BHE due to specific legal or regulatory restrictions, including, but not limited to, maximum debt-to-total capitalization percentages and commitments made to state commissions. As a result of these restrictions, BHE's subsidiaries had restricted net assets of \$25.3 billion as of December 31, 2024.

(19) Components of Accumulated Other Comprehensive Loss, Net

The following table shows the change in accumulated other comprehensive loss attributable to BHE shareholders by each component of other comprehensive income (loss), net of applicable income taxes, for the year ended December 31 (in millions):

	Unrecognized Amounts on Retirement Benefits	Foreign Currency Translation Adjustment	Unrealized Gains (Losses) on Cash Flow Hedges	Noncontrolling Interests	AOCI Attributable To BHE Shareholders, Net
Balance, December 31, 2021	\$ (318)	\$ (1,086)	\$ 59	\$ 5	\$ (1,340)
Other comprehensive (loss) income	(72)	(810)	76	(3)	(809)
Balance, December 31, 2022	(390)	(1,896)	135	2	(2,149)
Other comprehensive (loss) income	(36)	346	(64)	—	246
Purchase of noncontrolling interest	—	—	—	(1)	(1)
Balance, December 31, 2023	(426)	(1,550)	71	1	(1,904)
Other comprehensive income (loss)	5	(449)	7	—	(437)
Balance, December 31, 2024	<u>\$ (421)</u>	<u>\$ (1,999)</u>	<u>\$ 78</u>	<u>\$ 1</u>	<u>\$ (2,341)</u>

Reclassifications from AOCI to net income for the years ended December 31, 2024, 2023 and 2022 were insignificant. Additionally, refer to the "Foreign Operations" discussion in Note 13 for information about unrecognized amounts on retirement benefits reclassifications from AOCI that do not impact net income in their entirety.

(20) Variable Interest Entities and Noncontrolling Interests

The primary beneficiary of a VIE is required to consolidate the VIE and to disclose certain information about its significant variable interests in the VIE. The primary beneficiary of a VIE is the entity that has both (i) the power to direct the activities that most significantly impact the entity's economic performance and (ii) the obligation to absorb losses or receive benefits from the entity that could potentially be significant to the VIE.

As of December 31, 2024, BHE holds 75% of the limited partner interest and holds 100% of the general partner interest of Cove Point. BHE concluded that Cove Point is a VIE due to the limited partner lacking the characteristics of a controlling financial interest. BHE is the primary beneficiary of Cove Point as it has the power to direct the activities that most significantly impact its economic performance as well as the obligation to absorb losses and benefits which could be significant to it.

Included in noncontrolling interests on the Consolidated Balance Sheets are (i) Brookfield Super-Core Infrastructure Partner's 25% interest in Cove Point and (ii) preferred securities of subsidiaries of \$58 million as of December 31, 2024 and 2023, consisting of \$56 million of 8.061% cumulative preferred securities of Northern Electric plc, a subsidiary of Northern Powergrid, which are redeemable in the event of the revocation of Northern Electric plc's electricity distribution license by the Secretary of State, and \$2 million of nonredeemable preferred stock of PacifiCorp.

(21) Supplemental Cash Flow Disclosures

The summary of supplemental cash flow disclosures as of and for the years ended December 31 is as follows (in millions):

	2024	2023	2022
Supplemental disclosure of cash flow information:			
Interest paid, net of amounts capitalized	\$ 2,304	\$ 2,109	\$ 2,071
Income taxes received, net ⁽¹⁾	\$ 1,501	\$ 1,370	\$ 1,863
Supplemental disclosure of non-cash investing and financing transactions:			
Accruals related to property, plant and equipment additions	\$ 1,337	\$ 1,494	\$ 1,049
Issuance of note payable in exchange for common stock	\$ 600	\$ —	\$ —
BHE B Merger:			
Tax equity investments, net of deferred taxes	\$ 985	\$ —	\$ —
U.S. Treasury Bill exchanged for BHE B preferred stock	(364)	—	—
Issuance of 4% Perpetual Preferred Stock	(481)	—	—
BHE B common equity	(140)	—	—
Total	\$ —	\$ —	\$ —

- (1) Includes \$1,580 million, \$1,479 million and \$1,961 million of income taxes received from Berkshire Hathaway in 2024, 2023 and 2022, respectively.

(22) Segment Information

The Company's chief operating decision maker ("CODM") is its President and Chief Executive Officer. Earnings on common shares for each reportable segment are considered by the CODM in allocating resources and capital. The CODM generally considers actual results versus historical results, budgets or forecasts, as well as unique risks and opportunities, when making decisions about the allocation of resources and capital to each reportable segment. The Company's reportable segments with foreign operations include Northern Powergrid, whose business is principally in the United Kingdom, and BHE Transmission, whose business includes operations in Canada. Intersegment eliminations and adjustments, including the allocation of goodwill, have been made. Information related to the Company's reportable segments is shown below for the year ended December 31 (in millions):

	2024									
	PacifiCorp	MidAmerican Funding	NV Energy	Northern Powergrid	BHE Pipeline Group	BHE Transmission	BHE Renewables	HomeServices	BHE and Other ⁽¹⁾	Total
Operating revenue	\$ 6,600	\$ 3,251	\$ 4,140	\$ 1,627	\$ 3,810	\$ 801	\$ 1,475	\$ 4,354	\$ (138)	\$ 25,920
Cost of sales	2,752	797	2,290	148	198	23	544	3,145	(136)	9,761
Operations and maintenance	1,968	879	560	240	1,094	163	483	1,309	84	6,780
Depreciation and amortization	1,152	1,001	554	346	580	233	270	46	2	4,184
Interest expense	756	434	291	138	178	151	135	9	624	2,716
Interest and dividend income	193	40	36	8	63	3	16	24	60	443
Income tax expense (benefit)	(240)	(843)	67	128	365	18	(925)	(28)	(124)	(1,582)
Equity income (loss)	—	—	3	1	83	89	(503)	9	—	(318)
Other segment items	121	(32)	27	(89)	(309)	(42)	(34)	(13)	485	114
Earnings on common shares	<u>\$ 526</u>	<u>\$ 991</u>	<u>\$ 444</u>	<u>\$ 547</u>	<u>\$ 1,232</u>	<u>\$ 263</u>	<u>\$ 447</u>	<u>\$ (107)</u>	<u>\$ (43)</u>	<u>\$ 4,300</u>
Capital expenditures	<u>\$ 3,102</u>	<u>\$ 1,704</u>	<u>\$ 1,777</u>	<u>\$ 657</u>	<u>\$ 1,050</u>	<u>\$ 253</u>	<u>\$ 455</u>	<u>\$ 8</u>	<u>\$ 7</u>	<u>\$ 9,013</u>
Property, plant and equipment, net	<u>\$ 29,120</u>	<u>\$ 22,766</u>	<u>\$13,840</u>	<u>\$ 8,165</u>	<u>\$17,373</u>	<u>\$ 5,812</u>	<u>\$ 6,377</u>	<u>\$ 151</u>	<u>\$ 165</u>	<u>\$103,769</u>
Total assets	<u>\$ 36,134</u>	<u>\$ 28,203</u>	<u>\$18,708</u>	<u>\$ 9,803</u>	<u>\$22,114</u>	<u>\$ 9,098</u>	<u>\$ 11,963</u>	<u>\$ 3,382</u>	<u>\$ 735</u>	<u>\$140,140</u>

2023										
	PacifiCorp	MidAmerican Funding	NV Energy	Northern Powergrid	BHE Pipeline Group	BHE Transmission	BHE Renewables	HomeServices	BHE and Other ⁽¹⁾	Total
Operating revenue	\$ 5,936	\$ 3,393	\$ 4,523	\$ 1,303	\$ 3,774	\$ 799	\$ 1,710	\$ 4,322	\$ (158)	\$ 25,602
Cost of sales	2,246	952	2,807	179	256	25	748	3,120	(156)	10,177
Operations and maintenance	3,148	851	511	199	1,052	139	472	1,138	84	7,594
Depreciation and amortization	1,126	908	615	455	542	256	266	50	2	4,220
Interest expense	546	362	259	119	150	150	160	13	656	2,415
Interest and dividend income	100	23	95	2	56	3	13	16	104	412
Income tax expense (benefit)	(553)	(695)	41	122	300	19	(876)	5	(62)	(1,699)
Equity income (loss)	—	—	3	(1)	75	75	(448)	8	—	(288)
Other segment items	9	(58)	6	(65)	(526)	(42)	13	(7)	637	(33)
Earnings on common shares	<u>\$ (468)</u>	<u>\$ 980</u>	<u>\$ 394</u>	<u>\$ 165</u>	<u>\$ 1,079</u>	<u>\$ 246</u>	<u>\$ 518</u>	<u>\$ 13</u>	<u>\$ 59</u>	<u>\$ 2,986</u>
Capital expenditures	<u>\$ 3,226</u>	<u>\$ 1,833</u>	<u>\$ 1,797</u>	<u>\$ 557</u>	<u>\$ 1,294</u>	<u>\$ 206</u>	<u>\$ 177</u>	<u>\$ 41</u>	<u>\$ 17</u>	<u>\$ 9,148</u>
Property, plant and equipment, net	<u>\$ 27,051</u>	<u>\$ 21,971</u>	<u>\$12,480</u>	<u>\$ 8,007</u>	<u>\$16,904</u>	<u>\$ 6,273</u>	<u>\$ 6,169</u>	<u>\$ 187</u>	<u>\$ 206</u>	<u>\$ 99,248</u>
Total assets	<u>\$ 33,757</u>	<u>\$ 27,331</u>	<u>\$17,788</u>	<u>\$ 9,596</u>	<u>\$21,723</u>	<u>\$ 9,624</u>	<u>\$ 11,045</u>	<u>\$ 3,407</u>	<u>\$ 3,569</u>	<u>\$137,840</u>
2022										
	PacifiCorp	MidAmerican Funding	NV Energy	Northern Powergrid	BHE Pipeline Group	BHE Transmission	BHE Renewables	HomeServices	BHE and Other ⁽¹⁾	Total
Operating revenue	\$ 5,679	\$ 4,025	\$ 3,824	\$ 1,365	\$ 3,844	\$ 732	\$ 1,737	\$ 5,268	\$ (137)	\$ 26,337
Cost of sales	1,979	1,442	2,093	203	455	8	713	3,784	(136)	10,541
Operations and maintenance	1,227	828	483	190	935	110	405	1,268	39	5,485
Depreciation and amortization	1,120	1,168	566	361	508	239	265	56	3	4,286
Interest expense	431	333	221	133	148	153	179	7	611	2,216
Interest and dividend income	46	7	65	3	10	1	8	2	12	154
Income tax expense (benefit)	(61)	(776)	56	75	276	14	(879)	47	(668)	(1,916)
Equity income (loss)	—	—	3	—	109	76	(382)	9	—	(185)
Other segment items	(108)	(90)	(46)	(21)	(601)	(38)	(37)	(17)	(2,061)	(3,019)
Earnings on common shares	<u>\$ 921</u>	<u>\$ 947</u>	<u>\$ 427</u>	<u>\$ 385</u>	<u>\$ 1,040</u>	<u>\$ 247</u>	<u>\$ 643</u>	<u>\$ 100</u>	<u>\$ (2,035)</u>	<u>\$ 2,675</u>
Capital expenditures	<u>\$ 2,166</u>	<u>\$ 1,869</u>	<u>\$ 1,113</u>	<u>\$ 768</u>	<u>\$ 1,157</u>	<u>\$ 200</u>	<u>\$ 140</u>	<u>\$ 48</u>	<u>\$ 44</u>	<u>\$ 7,505</u>
Property, plant and equipment, net	<u>\$ 24,430</u>	<u>\$ 21,092</u>	<u>\$10,993</u>	<u>\$ 7,445</u>	<u>\$16,216</u>	<u>\$ 6,209</u>	<u>\$ 6,236</u>	<u>\$ 188</u>	<u>\$ 234</u>	<u>\$ 93,043</u>
Total assets	<u>\$ 30,559</u>	<u>\$ 26,077</u>	<u>\$16,676</u>	<u>\$ 9,005</u>	<u>\$21,005</u>	<u>\$ 9,334</u>	<u>\$ 11,797</u>	<u>\$ 3,436</u>	<u>\$ 5,951</u>	<u>\$133,840</u>

(1) The differences between the reportable segment amounts and the consolidated amounts, described as BHE and Other, relate to other corporate entities, corporate functions and intersegment eliminations.

- (2) Income tax (benefit) expense includes the tax attributes of disregarded entities that are not required to pay income taxes and the earnings of which are taxable directly to BHE.

The following table summarizes the other segment items category by the Company's reportable segments:

	<u>PacifiCorp</u>	<u>MidAmerican Funding</u>	<u>NV Energy</u>	<u>Northern Powergrid</u>	<u>BHE Pipeline Group</u>	<u>BHE Transmission</u>	<u>BHE Renewables</u>	<u>HomeServices</u>
Property and other taxes	x	x	x	x	x	x	x	x
Capitalized interest	x	x	x	x	x	x	x	
Allowance for equity funds	x	x	x		x	x		
Gains (losses) on marketable securities, net	x	x	x		x	x	x	x
Other income (expense), net	x	x	x	x	x	x	x	x
Net income attributable to noncontrolling interests	x			x	x	x	x	x

The following table summarizes the Company's revenue and property, plant and equipment, net by geographic region for the years ended December 31 (in millions):

	<u>2024</u>	<u>2023</u>	<u>2022</u>
Operating revenue by country:			
U.S.	\$ 23,574	\$ 23,593	\$ 24,263
United Kingdom	1,577	1,277	1,345
Canada	719	706	709
Australia	44	20	20
Other	6	6	—
Total operating revenue by country	<u>\$ 25,920</u>	<u>\$ 25,602</u>	<u>\$ 26,337</u>

Property, plant and equipment, net by country:

U.S.	\$ 89,958	\$ 85,128	\$ 79,578
United Kingdom	7,890	7,710	6,959
Canada	5,705	6,178	6,091
Australia	216	232	415
Total property, plant and equipment, net by country	<u>\$ 103,769</u>	<u>\$ 99,248</u>	<u>\$ 93,043</u>

The following table shows the changes in the carrying amount of goodwill by reportable segment for the years ended December 31, 2024 and 2023 (in millions):

	<u>PacifiCorp</u>	<u>MidAmerican Funding</u>	<u>NV Energy</u>	<u>Northern Powergrid</u>	<u>BHE Pipeline Group</u>	<u>BHE Transmission</u>	<u>BHE Renewables</u>	<u>HomeServices</u>	<u>Total</u>
December 31, 2022	\$ 1,129	\$ 2,102	\$ 2,369	\$ 917	\$ 1,814	\$ 1,461	\$ 95	\$ 1,602	\$ 11,489
Acquisitions	—	—	—	—	—	—	—	1	1
Foreign currency translation	—	—	—	33	—	31	—	—	64
Other	—	—	—	—	—	—	—	(7)	(7)
December 31, 2023	1,129	2,102	2,369	950	1,814	1,492	95	1,596	11,547
Foreign currency translation	—	—	—	(10)	—	(119)	—	—	(129)
Other	—	—	—	—	—	—	—	(5)	(5)
December 31, 2024	<u>\$ 1,129</u>	<u>\$ 2,102</u>	<u>\$ 2,369</u>	<u>\$ 940</u>	<u>\$ 1,814</u>	<u>\$ 1,373</u>	<u>\$ 95</u>	<u>\$ 1,591</u>	<u>\$ 11,413</u>

PacifiCorp and its subsidiaries
Consolidated Financial Section

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

The following is management's discussion and analysis of certain significant factors that have affected the consolidated financial condition and results of operations of PacifiCorp during the periods included herein. Explanations include management's best estimate of the impact of weather, customer growth, usage trends and other factors. This discussion should be read in conjunction with PacifiCorp's historical Consolidated Financial Statements and Notes to Consolidated Financial Statements in Item 8 of this Form 10-K. PacifiCorp's actual results in the future could differ significantly from the historical results.

Results of Operations

Overview

Net income for the year ended December 31, 2024, was \$539 million, an increase of \$1,007 million, compared to 2023 net loss of \$468 million primarily due to lower estimated losses of \$1,331 million associated with the Wildfires, net of expected insurance recoveries, higher utility margin and higher allowances for equity and borrowed funds used during construction. These items were partially offset by lower income tax benefit, increased operations and maintenance expense, higher net interest expense, and higher depreciation and amortization expense. Utility margin increased primarily due to higher retail prices and volumes, lower coal-fueled generation volumes, lower purchased electricity prices, lower natural gas-fueled generation prices, and higher net wheeling revenue, partially offset by lower net power cost deferrals, driven by higher amortization of prior deferrals and lower current year deferrals, higher purchased electricity volumes, higher coal-fueled generation prices, higher natural-gas generation volumes and lower wholesale revenue from lower volumes and prices. Retail customer volumes increased 3.1% primarily due to an increase in commercial, industrial and irrigation customer usage and an increase in the average number of customers, partially offset by a decrease in the residential customer usage and unfavorable impacts of weather. Energy generated decreased 807 gigawatt-hours, or 2%, primarily due to lower coal-fueled and hydroelectric-powered generation, partially offset by higher natural gas-fueled and wind-powered generation. Wholesale electricity sales volumes decreased 22% and purchased electricity volumes increased 12%.

Net loss for the year ended December 31, 2023, was \$468 million, a decrease of \$1,388 million, compared to 2022 net income of \$920 million primarily due to an increase in estimated losses of \$1,613 million associated with the Wildfires, net of expected insurance recoveries, higher operations and maintenance expense, higher property and other taxes and lower utility margin. These items were partially offset by higher income tax benefit and lower other expense. Utility margin decreased primarily due to higher purchased electricity costs from higher volumes and prices, lower wholesale volumes, higher coal-fueled generation prices, higher natural gas-fueled generation volumes and lower retail volumes, partially offset by higher retail rates, higher net power cost deferrals, lower coal-fueled generation volumes, lower natural gas-fueled generation prices and higher average wholesale prices. Retail customer volumes decreased 0.8% primarily due to unfavorable impacts of weather and lower industrial, irrigation and residential customer usage, partially offset by higher commercial customer usage and an increase in the average number of customers. Energy generated decreased 6,762 gigawatt-hours, or 13%, primarily due to lower coal-fueled and wind-powered volumes, partially offset by higher natural gas-fueled and hydroelectric-powered volumes. Wholesale electricity sales volumes decreased 40% and purchased electricity volumes increased 32%.

Non-GAAP Financial Measure

Management utilizes various key financial measures that are prepared in accordance with GAAP, as well as non-GAAP financial measures such as utility margin, to help evaluate results of operations. Utility margin is calculated as operating revenue less cost of fuel and energy, which are captions presented on the Consolidated Statements of Operations.

PacifiCorp's cost of fuel and energy is generally recovered from its retail customers through regulatory recovery mechanisms and, as a result, changes in PacifiCorp's expenses included in regulatory recovery mechanisms result in comparable changes to revenue. As such, management believes utility margin more appropriately and concisely explains results of operations rather than a discussion of revenue and cost of fuel and energy separately. Management believes the presentation of utility margin provides meaningful and valuable insight into the information management considers important to understanding the business and a measure of comparability to others in the industry.

Utility margin is not a measure calculated in accordance with GAAP and should be viewed as a supplement to, and not a substitute for, operating income, which is the most directly comparable financial measure prepared in accordance with GAAP. The following table provides a reconciliation of utility margin to operating income for the years ended December 31 (in millions):

	2024	2023	Change		2023	2022	Change	
Utility margin:								
Operating revenue	\$ 6,600	\$ 5,936	\$ 664	11 %	\$ 5,936	\$ 5,679	\$ 257	5 %
Cost of fuel and energy	2,752	2,246	506	23	2,246	1,979	267	13
Utility margin	3,848	3,690	158	4	3,690	3,700	(10)	—
Operations and maintenance	1,603	1,469	134	9	1,469	1,163	306	26
Wildfires losses, net of recoveries	346	1,677	(1,331)	(79)	1,677	64	1,613	*
Depreciation and amortization	1,152	1,126	26	2	1,126	1,120	6	1
Property and other taxes	218	215	3	1	215	195	20	10
Operating income (loss)	\$ 529	\$ (797)	\$ 1,326	166 %	\$ (797)	\$ 1,158	\$ (1,955)	(169)%

* Not meaningful

Utility Margin

A comparison of key operating results related to utility margin is as follows for the years ended December 31:

	2024	2023	Change		2023	2022	Change	
Utility margin (in millions):								
Operating revenue	\$ 6,600	\$ 5,936	\$ 664	11 %	\$ 5,936	\$ 5,679	\$ 257	5 %
Cost of fuel and energy	2,752	2,246	506	23	2,246	1,979	267	13
Utility margin	<u>\$ 3,848</u>	<u>\$ 3,690</u>	<u>\$ 158</u>	4 %	<u>\$ 3,690</u>	<u>\$ 3,700</u>	<u>\$ (10)</u>	— %
Sales (GWhs):								
Residential	18,253	18,159	94	1 %	18,159	18,425	(266)	(1)%
Commercial ⁽¹⁾	21,585	20,491	1,094	5	20,491	19,570	921	5
Industrial ⁽¹⁾	17,101	16,705	396	2	16,705	17,622	(917)	(5)
Other ⁽¹⁾	1,536	1,341	195	15	1,341	1,547	(206)	(13)
Total retail	58,475	56,696	1,779	3	56,696	57,164	(468)	(1)
Wholesale	2,280	2,911	(631)	(22)	2,911	4,836	(1,925)	(40)
Total sales	<u>60,755</u>	<u>59,607</u>	<u>1,148</u>	2 %	<u>59,607</u>	<u>62,000</u>	<u>(2,393)</u>	(4)%
Average number of retail customers								
(in thousands)	2,104	2,069	35	2 %	2,069	2,037	32	2 %
Average revenue per MWh:								
Retail	\$105.56	\$96.25	\$ 9.31	10 %	\$96.25	\$ 89.33	\$ 6.92	8 %
Wholesale	\$ 54.30	\$ 66.04	\$(11.74)	(18)%	\$ 66.04	\$ 61.39	\$ 4.65	8 %
Heating degree days								
	9,526	10,415	(889)	(9)%	10,415	10,767	(352)	(3)%
Cooling degree days								
	2,339	2,183	156	7 %	2,183	2,451	(268)	(11)%
Sources of energy (GWhs) ⁽¹⁾ :								
Coal	18,122	21,950	(3,828)	(17)%	21,950	28,390	(6,440)	(23)%
Natural gas	17,045	14,050	2,995	21	14,050	13,686	364	3
Wind ⁽²⁾	6,918	6,500	418	6	6,500	7,238	(738)	(10)
Hydroelectric and other ⁽²⁾	2,866	3,258	(392)	(12)	3,258	3,206	52	2
Total energy generated	44,951	45,758	(807)	(2)	45,758	52,520	(6,762)	(13)
Energy purchased	20,596	18,404	2,192	12	18,404	13,968	4,436	32
Total	<u>65,547</u>	<u>64,162</u>	<u>1,385</u>	2 %	<u>64,162</u>	<u>66,488</u>	<u>(2,326)</u>	(3)%
Average cost of energy per MWh:								
Energy generated ⁽³⁾	\$ 24.53	\$ 24.65	\$ (0.12)	— %	\$ 24.65	\$ 22.86	\$ 1.79	8 %
Energy purchased	\$ 75.73	\$ 80.38	\$ (4.65)	(6)%	\$ 80.38	\$ 71.15	\$ 9.23	13 %

(1) GWh amounts are net of energy used by the related generating facilities.

(2) All or some of the renewable energy attributes associated with generation from these sources may be: (a) used in future years to comply with RPS or other regulatory requirements or (b) sold to third parties in the form of RECs or other environmental commodities.

(3) The average cost per MWh of energy generated includes only the cost of fuel associated with the generating facilities.

Year Ended December 31, 2024 Compared to Year Ended December 31, 2023

Utility margin increased \$158 million, or 4%, for 2024 compared to 2023 primarily due to:

- \$716 million of higher retail revenue primarily due to higher average prices and higher volumes. Retail customer volumes increased 3.1%, primarily due to a higher Utah, Oregon and Washington commercial customer usage and Utah residential customer usage, higher industrial customer usage in Washington, Wyoming and Idaho, higher irrigation customer usage across the service territory, mainly in Idaho, and increase in the average number of residential and commercial customers. These increases were partially offset by lower residential customer usage across the western service territory, mainly in Oregon and unfavorable weather impacts across the service territory;
- \$39 million of lower coal-fueled generation costs due to lower volumes, partially offset by higher prices; and
- \$14 million of higher net wheeling revenue.

The increases above were partially offset by:

- \$440 million of lower net power cost deferrals in accordance with established adjustment mechanisms driven by higher amortization of prior deferrals and lower current year deferrals;
- \$81 million of higher purchased electricity costs from higher volumes, partially offset by lower average market prices;
- \$68 million of lower wholesale revenue primarily due to lower volumes and lower average prices; and
- \$16 million of higher natural gas-fueled generation costs primarily due to higher volumes, partially offset by lower average prices.

Operations and maintenance increased \$134 million, or 9%, for 2024 compared to 2023 primarily due to:

- \$38 million of higher vegetation management and other wildfire mitigation costs, primarily due to higher amortization of amounts previously deferred in Oregon and higher costs;
- \$32 million of higher liability insurance costs net of current year deferral of \$45 million for a portion of Oregon's and Idaho's shares of higher insurance premiums;
- \$23 million of higher DSM amortization expense;
- \$21 million increase in salary and benefit expenses;
- \$15 million increase due to prior year establishment of a regulatory asset associated with the December 2023 California general rate case outcome compounded by amortization in the current year;
- \$11 million increase due to costs associated with the Lower Klamath Project;
- \$10 million of plant disallowances substantially due to Oregon rate case order partial disallowance of wildfire mitigation transmission plant investments; and
- \$4 million of higher legal fees.

The increases above were partially offset by:

- \$11 million decrease in general and plant maintenance costs; and
- \$9 million decrease in bad debt expense.

Wildfires losses, net of recoveries decreased \$1,331 million, or 79%, for 2024 compared to 2023 due to lower accruals for estimated losses associated with the Wildfires, net of expected insurance recoveries in 2024 compared to 2023.

Depreciation and amortization increased \$26 million, or 2%, for 2024 compared to 2023 primarily due to higher plant in-service balances in the current year, partially offset by cessation of Washington incremental depreciation of certain coal plants.

Interest expense increased \$210 million, or 38%, for 2024 compared to 2023 primarily due to higher average long-term debt balances due to the issuance of \$3.8 billion of first mortgage bonds in January 2024.

Allowance for borrowed and equity funds increased \$109 million, or 51%, for 2024 compared to 2023 primarily due to higher qualified construction work-in-progress balances, partially offset by lower rates.

Interest and dividend income increased \$93 million, or 95%, for 2024 compared to 2023 primarily due to higher investment income of \$45 million from higher cash equivalents and higher regulatory asset interest income of \$45 million primarily from higher deferred net power cost balances.

Income tax benefit decreased \$317 million, or 57%, for 2024 compared to 2023. The effective tax rate was (78)% and 54% for 2024 and 2023, respectively. The \$317 million decrease is primarily due to higher prior year loss accruals, net of expected insurance recoveries, associated with the Wildfires and lower current year benefit from the effects of ratemaking, partially offset by higher recognized PTCs from PacifiCorp's wind-powered generating facilities.

Year Ended December 31, 2023 Compared to Year Ended December 31, 2022

Utility margin decreased \$10 million for 2023 compared to 2022 primarily due to:

- \$485 million of higher purchased electricity costs from higher volumes and prices;
- \$105 million of lower wholesale revenue primarily due to lower volumes, partially offset by higher average prices; and
- \$18 million of lower net wheeling revenue.

The decreases above were partially offset by:

- \$350 million of higher retail revenue primarily due to higher average prices, partially offset by lower volumes. Retail customer volumes decreased 0.8%, primarily due to lower industrial customer usage across the service territory, lower residential customer usage across the western states, primarily in Oregon, lower irrigation customer usage across the service territory and unfavorable residential and commercial weather related impacts across the service territory, partially offset by higher commercial and residential customer usage across the eastern states, primarily in Utah, higher Oregon commercial customer usage and an increase in the average number of residential and commercial customers across the service territory;
- \$147 million from higher deferred net power costs in accordance with established adjustment mechanisms;
- \$54 million of lower natural gas-fueled generation costs primarily due to lower average prices, partially offset by higher volumes;
- \$21 million of lower coal-fueled generation costs due to lower volumes, partially offset by higher average prices;
- \$12 million associated with the recognition of California greenhouse gas allowances related revenues driven by timing of customer credits (offset in retail revenue);
- \$8 million of higher other revenue due to the reestablishment of customer late fees assessments; and
- \$5 million of higher REC sales.

Operations and maintenance increased \$306 million, or 26%, for 2023 compared to 2022 primarily due to:

- \$114 million increase in vegetation management and wildfire mitigation costs due to higher costs of \$19 million, lower current year regulatory deferrals of \$70 million and higher amortization of prior regulatory deferrals of \$25 million;
- \$42 million increase in insurance premiums due to higher cost of third-party liability insurance coverage resulting from the impact of industry-wide catastrophic wildfires;
- \$41 million increase in plant operations and maintenance costs;
- \$33 million of higher legal fees primarily related to wildfires matters;
- \$25 million increase in DSM amortization expense driven by higher spend in Oregon, Washington, Utah and Idaho (offset in retail revenue);
- \$17 million of higher bad debt expense;
- \$15 million increase from higher write-offs of construction work-in-progress balances resulting from changes in planned spending for certain growth projects;
- \$14 million higher labor and employee-related expenses;
- \$9 million increase in amortization of various regulatory balances (offset in other revenue); and
- \$6 million increase in general injuries and damages accruals.

The increases above were partially offset by:

- \$9 million of operations and maintenance expense related to regulatory deferrals resulting from the December 2023 California general rate case order.

Wildfires losses, net of recoveries increased \$1,613 million for 2023 compared to 2022 due to an increase in estimated losses associated with the Wildfires, net of expected insurance recoveries.

Depreciation and amortization increased \$6 million, or 1%, for 2023 compared to 2022 primarily due to higher plant-in-service balances in the current year and prior year Oregon deferral associated with the depreciation of certain wind-powered generating facilities compounded by current year amortization, partially offset by decreases mainly due to the extension of Jim Bridger Units 1 and 2 lives in Oregon as a result of the planned gas conversion and lower amortization of certain Klamath related deferrals in the eastern states that became fully amortized in the prior year.

Property and other taxes increased \$20 million, or 10%, for 2023 compared to 2022 primarily due to prior year favorable Utah property tax appeal settlement.

Interest expense increased \$115 million, or 27%, for 2023 compared to 2022 primarily due to higher average long- and short-term debt balances, higher interest rates, and higher interest expense on transmission readiness, security and network deposits due to higher average deposits on hand.

Allowance for borrowed and equity funds increased \$112 million for 2023 compared to 2022 primarily due to higher qualified construction work-in-progress balances, partially offset by lower rates.

Interest and dividend income increased \$54 million for 2023 compared to 2022 primarily due to higher deferred net power cost regulatory asset balances and higher investment income primarily from higher average interest rates.

Other, net increased \$25 million for 2023 compared to 2022 primarily due to an increase in cash surrender value of corporate-owned life insurance policies, lower pension costs and favorable change in the long-term incentive plan primarily due to market movements (offset in operations and maintenance expense).

Income tax benefit increased \$491 million for 2023 compared to 2022. The effective tax rate was 54% and (7)% for 2023 and 2022, respectively. The \$491 million increase is primarily due to the increase in the accruals, net of expected insurance recoveries for the Wildfires, a decrease to the valuation allowance for state net operating losses and higher benefit from the effects of ratemaking, partially offset by lower PTCs from PacifiCorp's wind-powered generating facilities.

Liquidity and Capital Resources

Overview

PacifiCorp's liquidity has been materially impacted by the Wildfires, and it may be unable to maintain sufficient levels of cash or obtain necessary short- and long-term financing to fund its operations, implement its business strategy, make interest payments, make scheduled repayments of long-term debt, finance its capital investments and fund potential future settlements associated with the Wildfires. To help mitigate PacifiCorp's liquidity pressures, BHE has indicated that it will suspend dividends for the next several years in order to allow PacifiCorp to accumulate cash that may be necessary in the event of additional future settlements associated with the Wildfires.

Additionally, to the extent PacifiCorp is unable to obtain additional surety bonds in the event of further unfavorable trial verdicts associated with the Wildfires, it may be required to post letters of credit or cash to secure such judgments. Such requirements could further reduce PacifiCorp's liquidity and availability under its revolving credit facility as described below under "Credit Facility" and "Letters of Credit" and could result in additional long-term debt offerings. Refer also to additional potential restrictions related to PacifiCorp's first mortgage bonds and credit facilities described below under "Financing Activities."

As of December 31, 2024, PacifiCorp's issuer credit ratings for its senior secured debt and its issuer credit ratings for senior unsecured debt from the recognized credit rating agencies were investment grade. While PacifiCorp's credit ratings remain investment grade, additional unfavorable wildfire litigation outcomes could result in additional pressure on the credit ratings. Further declines in PacifiCorp's credit ratings could limit investors' ability to purchase PacifiCorp's first mortgage bonds, as well as trigger investors to be required to sell PacifiCorp first mortgage bonds they currently hold. Additionally, in the event PacifiCorp's credit ratings decline to below investment grade, it would be required to post additional collateral associated with commodity agreements as a result of credit-risk-related contingent features in those contracts and counterparties could demand "adequate assurance" if there is a material adverse change in PacifiCorp's creditworthiness. Refer to additional information below under "Collateral and Contingent Features." Credit rating downgrades may impact the cost and availability of short-term borrowings, including credit facilities and commercial paper, and long-term debt costs.

Refer to Item 1A. Risk Factors of this Form 10-K for additional information regarding the risks associated with the changes in PacifiCorp's credit ratings, the litigation risk associated with the Wildfires and the increasing cost of third-party liability insurance coverage, all of which are expected to materially impact PacifiCorp's liquidity.

For more information about the risks that could materially affect PacifiCorp's financial condition, results of operations, liquidity, and cash flows, or that could cause future results to differ from historical results, see Item 1A. Risk Factors of this Form 10-K. This report contains forward-looking statements that are subject to various risks and uncertainties. These statements reflect management's judgment and opinions that are based on current estimates, expectations, and projections about future events and assumptions regarding these events and management's knowledge of facts as of the date of this report. See "Forward-Looking Statements" above for a list of some of the factors that may cause actual results to differ materially.

Net Liquidity

As of December 31, 2024, PacifiCorp's total net liquidity was as follows (in millions):

Cash and cash equivalents	\$	46
Credit facilities ⁽¹⁾		2,900
Less:		
Short-term debt		(240)
Tax-exempt bond support and letters of credit		(52)
Net credit facility		2,608
Total net liquidity	\$	2,654
Credit facilities:		
Maturity dates		2025, 2027

- (1) Refer to Note 7 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K and "Credit Facilities and Letters of Credit" below for further discussion regarding PacifiCorp's credit facilities.

Operating Activities

Net cash flows from operating activities for the years ended December 31, 2024 and 2023 were \$1,157 million and \$700 million, respectively. The increase is primarily due to higher collections from retail customers and insurance reimbursements related to wildfire liabilities, partially offset by higher operating expenses, higher wholesale purchases and lower wholesale sales, and higher fuel purchases.

Net cash flows from operating activities for the years ended December 31, 2023 and 2022 were \$700 million and \$1,819 million, respectively. The decrease is primarily due to higher wildfire liability settlement payments, higher wholesale purchases and collateral returned to counterparties, partially offset by higher collections from retail customers.

The timing of PacifiCorp's income tax cash flows from period to period can be significantly affected by the estimated federal income tax payment methods selected and assumptions made for each payment date.

Investing Activities

Net cash flows from investing activities for the years ended December 31, 2024 and 2023 were \$(3.1) billion and \$(3.2) billion, respectively. The decrease in net cash outflows from investing activities is mainly due to a decrease in capital expenditures of \$124 million.

Net cash flows from investing activities for the years ended December 31, 2023 and 2022 were \$(3.2) billion and \$(2.2) billion, respectively. The increase in net cash outflows from investing activities is mainly due to an increase in capital expenditures of \$1.1 billion.

Financing Activities

Mortgage

PacifiCorp's Mortgage and Deed of Trust creates a lien on most of PacifiCorp's electric utility property, allowing the issuance of bonds based on a percentage of utility property additions, bond credits arising from retirement of previously outstanding bonds or deposits of cash. The amount of bonds that PacifiCorp may issue generally is also subject to a net earnings test. As of December 31, 2024, PacifiCorp estimated it would be able to issue up to \$2.1 billion of new first mortgage bonds under the most restrictive issuance test in the mortgage. Any issuances are subject to market conditions and amounts are further limited by regulatory authorizations or commitments or by covenants and tests contained in other financing agreements, as described below. PacifiCorp also has the ability to release property from the lien of the mortgage on the basis of property additions, bond credits or deposits of cash.

Debt Authorizations, Restrictions and Debt Covenants

PacifiCorp currently has regulatory authority from the OPUC and the IPUC to issue an additional \$5.0 billion of long-term debt. PacifiCorp's authorization from the IPUC is through April 2029. PacifiCorp must make a notice filing with the WUTC prior to any future issuance. PacifiCorp currently has an effective shelf registration statement filed with the SEC to issue an indeterminate amount of first mortgage bonds and unsecured debt securities through July 2027.

PacifiCorp currently has regulatory authority from the OPUC, the WUTC, the IPUC and the FERC to issue \$3.0 billion of short-term debt.

While PacifiCorp's current revolving credit facilities are unsecured, upon future renewal, PacifiCorp may be required to secure the facilities, which could further limit the amount of first mortgage bonds PacifiCorp can issue.

The credit facilities require that PacifiCorp's ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.65 to 1.0 as of the last day of each quarter. As of December 31, 2024, PacifiCorp's debt to total capitalization ratio was 0.57 to 1.0.

As of December 31, 2024, PacifiCorp was in compliance with all financial covenants that affect access to capital.

Short-term Debt

As of December 31, 2024 and 2023, PacifiCorp had \$240 million and \$1.6 billion of short-term debt outstanding at a weighted average rate of 4.65% and 6.16%. For further discussion, refer to Note 7 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Long-term Debt

In January 2024, PacifiCorp issued \$500 million of its 5.10% First Mortgage Bonds due February 2029, \$700 million of its 5.30% First Mortgage Bonds due February 2031, \$1.1 billion of its 5.45% First Mortgage Bonds due February 2034 and \$1.5 billion of its 5.80% First Mortgage Bonds due January 2055, for a total of \$3.8 billion. PacifiCorp initially used a portion of the net proceeds to repay outstanding short-term debt and intends to use the remaining net proceeds to fund capital expenditures and for general corporate purposes.

In June 2024, PacifiCorp terminated its \$900 million unsecured delayed draw term loan facility expiring in June 2025 and entered into a new credit facility discussed below.

PacifiCorp made repayments on long-term debt totaling \$591 million and \$449 million during the years ended December 31, 2024 and 2023, respectively.

Credit Facilities and Letters of Credit

In June 2024, PacifiCorp amended its existing \$2.0 billion unsecured credit facility expiring in June 2026. The amendment extended the expiration date to June 2027. Upon termination of the delayed draw term loan discussed above, in June 2024, PacifiCorp entered into a new \$900 million 364-day unsecured credit facility expiring in June 2025.

As of December 31, 2024, PacifiCorp had \$255 million of letter of credit capacity under its \$2.0 billion revolving credit facility of which no amount was outstanding, and \$488 million of letter of credit capacity outside of its \$2.0 billion revolving credit facility, of which \$34 million was outstanding and was utilized in support of certain transactions required by third parties. Subsequently, PacifiCorp added \$225 million of letter of credit capacity outside of its \$2.0 billion revolving credit facility. As of February 21, 2025, PacifiCorp's total letter of credit capacity outside of its \$2.0 billion revolving credit facility was \$713 million.

As of December 31, 2023, PacifiCorp had \$255 million of letter of credit capacity under the \$2.0 billion revolving credit facility of which \$31 million was outstanding and was utilized as a standby letter of credit, and \$168 million of letter of credit capacity outside of its \$2.0 billion revolving credit facility, of which \$55 million was outstanding and was utilized in support of certain transactions required by third parties.

For further discussion and amounts outstanding, refer to Note 7 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Preferred Stock

As of December 31, 2024 and 2023, PacifiCorp had non-redeemable preferred stock outstanding with an aggregate stated value of \$2 million.

On December 17, 2024, PPW Holdings LLC, PacifiCorp's direct parent and sole holder of the common stock of PacifiCorp, commenced a tender offer to purchase for cash any and all of PacifiCorp's outstanding 6.00% and 7.00% Serial Preferred Stock (together the "Serial Preferred Stock"). After giving effect to the tender offer, which expired on January 24, 2025, PPW Holdings LLC held 2,494 shares of the 5,930 issued and outstanding shares of the 6.00% Serial Preferred Stock and 10,269 shares of the 18,046 issued and outstanding shares of the 7.00% Serial Preferred Stock.

On February 6, 2025, PacifiCorp filed a First Articles of Amendment to the Fourth Restated Articles of Incorporation of PacifiCorp authorizing a one-for-ten thousand reverse stock split (the "Reverse Stock Split") of the Serial Preferred Stock. The Reverse Stock Split became effective at 12:01 a.m. Eastern Time on February 10, 2025.

As a result of the Reverse Stock Split, every 10,000 shares of each of PacifiCorp's pre-reverse split Serial Preferred Stock were combined and reclassified into one share of Serial Preferred Stock, with a corresponding reduction in the number of authorized shares of Serial Preferred Stock from 3,500 thousand to 350 and change to stated value of \$100 to \$1,000,000 per share. No fractional shares were issued in connection with the Reverse Stock Split and shareholders who would have otherwise held a fractional share of Serial Preferred Stock received payment in cash.

As of February 10, 2025, there was one share of 7.00% Serial Preferred Stock outstanding, held by PPW Holdings LLC, and there were no shares of 6.00% Serial Preferred Stock outstanding. As a result, all issued and outstanding shares of PacifiCorp's preferred stock as of February 10, 2025, were held by PPW Holdings LLC.

Common Shareholder's Equity

In 2024 and 2023, PacifiCorp declared and paid dividends of \$— million and \$300 million, respectively, to PPW Holdings LLC.

Capitalization

PacifiCorp manages its capitalization and liquidity position to maintain a prudent capital structure with the objective of retaining strong investment grade credit ratings, which is expected to facilitate continuing access to flexible borrowing arrangements at favorable costs and rates. This objective, subject to periodic review and revision, attempts to balance the interests of all shareholders, customers and creditors and provide a competitive cost of capital and predictable capital market access.

Under existing or prospective authoritative accounting guidance, such as guidance pertaining to consolidations and leases, it is possible that new purchase power and gas agreements, transmission arrangements or amendments to existing arrangements may be accounted for as lease obligations on PacifiCorp's financial statements. While PacifiCorp has successfully amended covenants in financing arrangements that may be impacted, it may be more difficult for PacifiCorp to comply with its capitalization targets or regulatory commitments concerning minimum levels of common equity as a percentage of capitalization. This may lead PacifiCorp to seek amendments to its financing agreements and from regulators or take other actions.

Future Uses of Cash

PacifiCorp has available a variety of sources of liquidity and capital resources, both internal and external, including net cash flows from operating activities, public and private debt offerings, the issuance of commercial paper, the use of unsecured revolving credit facilities, bank loans, capital contributions and other sources. These sources are expected to provide funds required for current operations, capital expenditures, debt retirements and other capital requirements. The availability and terms under which PacifiCorp has access to external financing depends on a variety of factors, including PacifiCorp's credit ratings, investors' judgment of risk associated with PacifiCorp and conditions in the overall capital markets, including the condition of the utility industry.

Capital Expenditures

PacifiCorp has significant future capital requirements. Capital expenditure needs are reviewed regularly by management and may change significantly as a result of these reviews, which may consider, among other factors, impacts to customer rates; changes in environmental and other rules and regulations; outcomes of regulatory proceedings, including regulatory filings for Certificates of Public Convenience and Necessity; outcomes of legal actions associated with the Wildfires; changes in income tax laws; general business conditions; new customer requests; load projections; system reliability standards; the cost and efficiency of construction labor, equipment and materials; commodity prices; and the cost and availability of capital.

Historical and forecast capital expenditures, each of which exclude amounts for non-cash equity AFUDC and other non-cash items, for the years ended December 31 are as follows (in millions):

	Historical			Forecast		
	2022	2023	2024	2025	2026	2027
Wind generation	\$ 37	\$ 755	\$ 425	\$ 184	\$ 25	\$ 30
Electric distribution	543	673	761	795	708	608
Electric transmission	1,184	1,189	840	874	618	1,006
Wildfire mitigation	159	325	539	532	623	669
Other	243	284	537	541	630	806
Total	<u>\$ 2,166</u>	<u>\$ 3,226</u>	<u>\$ 3,102</u>	<u>\$ 2,926</u>	<u>\$ 2,604</u>	<u>\$ 3,119</u>

PacifiCorp's IRP is a roadmap for PacifiCorp's energy transition to renewable and carbon free generation resources, coal-to-natural gas conversion of certain coal-fueled units, renewable generation, associated transmission, load forecast and resource adequacy. PacifiCorp anticipates that the additional new renewable and carbon free generation will be a mixture of owned and contracted resources. PacifiCorp has included estimates for these new renewable and carbon free generation resources, conversion of certain coal-fueled units to natural gas-fueled units and associated transmission assets in its forecast capital expenditures for 2025 through 2027. These estimates are likely to change as a result of the IRP update and RFP process. PacifiCorp's historical and forecast capital expenditures include the following:

- Wind generation includes both growth projects and operating expenditures. Growth projects include construction of new wind-powered generating facilities and construction at existing wind-powered generating facility sites acquired from third parties totaling \$396 million for 2024, \$735 million for 2023 and \$23 million for 2022. PacifiCorp placed in-service 50 MWs at the Rock River I and 61 MWs at the Rock Creek I wind-powered generating facility in 2024 and 42 MWs at the Foote Creek III and Foote Creek IV wind-powered generating facilities in 2023. Planned spending for the construction of additional wind-powered generating facilities and those at acquired sites totals \$162 million in 2025 and is primarily for the Rock Creek I and Rock Creek II wind-powered generating facilities totaling approximately 529 MWs that are expected to be placed in-service in 2025.
- Electric distribution includes both growth projects and operating expenditures. Growth expenditures include spending on new customer connections totaled \$338 million in 2024, \$264 million in 2023 and \$182 million in 2022. Planned spending for new customer connections total \$433 million in 2025, \$393 million in 2026 and \$299 million in 2027. The remaining investments primarily relate to expenditures for distribution operations.
- Electric transmission includes both growth projects and operating expenditures. Transmission growth primarily reflects costs associated with major transmission projects. Expenditures for certain projects placed in-service during 2024 totaled \$382 million for 2024, \$738 million for 2023 and \$921 million for 2022. Planned spending for major transmission projects that are expected to be placed in-service through 2034 totals \$336 million in 2025, \$262 million in 2026 and \$342 million in 2027. The remaining investments primarily relate to expenditures for transmission operations, generation interconnection requests and other transmission segments.
- Wildfire mitigation includes operating expenditures. Expenditures totaled \$539 million in 2024, \$325 million in 2023 and \$159 million in 2022. Planned spending through 2026 is comprised of reducing wildfire risk in the FHCA by conversion of overhead systems to underground, replacing overhead bare wire conductor with covered conductors and deployment of advanced protection devices for faster fault detection. The efforts will also include an expansion of the weather station network and predictive tools for situational awareness across the entire service territory.
- Other includes both growth projects and operating expenditures. Expenditures for information technology totaled \$159 million in 2024, \$179 million in 2023 and \$155 million for 2022. Planned information technology spending totals \$178 million in 2025, \$237 million in 2026 and \$321 million in 2027. The remaining investments relate to operating projects that consist of routine expenditures for generation and other infrastructure needed to serve existing and expected demand

Off-Balance Sheet Arrangements

From time to time, PacifiCorp enters into arrangements in the normal course of business to facilitate commercial transactions with third parties that involve guarantees or similar arrangements. PacifiCorp currently has indemnification obligations in connection with the sale or transfer of certain assets. In addition, PacifiCorp evaluates potential obligations that arise out of variable interests in unconsolidated entities, determined in accordance with authoritative accounting guidance. PacifiCorp believes that the likelihood that it would be required to perform or otherwise incur any significant losses associated with any of these obligations is remote. Refer to Notes 11 and 19 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for more information on these obligations and arrangements.

Material Cash Requirements

PacifiCorp has cash requirements that may affect its consolidated financial condition that arise primarily from long-term debt (refer to Note 8); certain commitments and contingencies, including those associated with the Wildfires (refer to Note 14); and cost of removal and AROs (refer to Notes 6 and 11). Refer to the respective referenced note in Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

PacifiCorp has cash requirements relating to interest payments of \$12.6 billion on long-term debt, including \$689 million due in 2025.

Regulatory Matters

PacifiCorp is subject to comprehensive regulation. Refer to the discussion contained in Item 1 of this Form 10-K for further information regarding PacifiCorp's general regulatory framework and current regulatory matters.

Environmental Laws and Regulations

PacifiCorp is subject to federal, state and local laws and regulations regarding air quality, climate change, emissions performance standards, water quality, coal ash disposal and other environmental matters that have the potential to impact PacifiCorp's current and future operations. In addition to imposing continuing compliance obligations, these laws and regulations provide regulators with the authority to levy substantial penalties for noncompliance, including fines, injunctive relief and other sanctions. These laws and regulations are administered by various federal, state and local agencies. PacifiCorp believes it is in material compliance with all applicable laws and regulations, although many are subject to interpretation that may ultimately be resolved by the courts. Environmental laws and regulations continue to evolve, and PacifiCorp is unable to predict the impact of the changing laws and regulations on its operations and financial results.

Refer to "Environmental Laws and Regulations" in Item 1 of this Form 10-K for further discussion regarding environmental laws and regulations.

Collateral and Contingent Features

Debt and preferred securities of PacifiCorp are rated by credit rating agencies. Assigned credit ratings are based on each rating agency's assessment of PacifiCorp's ability to, in general, meet the obligations of its issued debt or preferred securities. The credit ratings are not a recommendation to buy, sell or hold securities, and there is no assurance that a particular credit rating will continue for any given period of time. As of December 31, 2024, PacifiCorp's issuer credit ratings for its senior secured debt and its issuer credit ratings for senior unsecured debt from the recognized credit rating agencies were investment grade.

PacifiCorp has no credit rating downgrade triggers that would accelerate the maturity dates of outstanding debt and a change in ratings is not an event of default under the applicable debt instruments. PacifiCorp's unsecured revolving credit facilities do not require the maintenance of a minimum credit rating level to draw upon their availability. However, commitment fees and interest rates under the credit facilities are tied to credit ratings and increase or decrease when the ratings change. A ratings downgrade could also increase the future cost of commercial paper, short- and long-term debt issuances or new credit facilities. Certain authorizations or exemptions by regulatory commissions for the issuance of securities are valid as long as PacifiCorp maintains investment grade ratings on senior secured debt. A downgrade below that level would necessitate new regulatory applications and approvals.

In accordance with industry practice, certain wholesale agreements, including derivative contracts, contain credit support provisions that in part base certain collateral requirements on credit ratings for senior unsecured debt as reported by one or more of the recognized credit rating agencies. These agreements may provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed specified rating-dependent threshold levels ("credit-risk-related contingent features"). These agreements and other agreements that do not refer to specified rating-dependent thresholds may provide the right for counterparties to demand "adequate assurance" if there is a material adverse change in PacifiCorp's creditworthiness. These rights can vary by contract and by counterparty. If all credit-risk-related contingent features or adequate assurance provisions for these agreements had been triggered as of December 31, 2024, PacifiCorp would have been required to post \$236 million of additional collateral. PacifiCorp's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation, outstanding accounts payable and receivable or other factors. Refer to Note 12 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for a discussion of PacifiCorp's collateral requirements specific to PacifiCorp's derivative contracts.

Inflation

PacifiCorp operates under a cost-of-service based rate-setting structure administered by various state commissions and the FERC. Under this rate-setting structure, PacifiCorp is allowed to include prudent costs in its rates, including the impact of inflation. PacifiCorp seeks to minimize the potential impact of inflation on its operations through the use of energy and other cost adjustment clauses and tariff riders, by employing prudent risk management and hedging strategies and entering into contracts with fixed pricing where possible by considering, among other areas, its impact on purchases of energy, operating expenses, materials and equipment costs, contract negotiations, future capital spending programs and long-term debt issuances. There can be no assurance that such actions will be successful.

New Accounting Pronouncements

For a discussion of new accounting pronouncements affecting PacifiCorp, refer to Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Critical Accounting Estimates

Certain accounting measurements require management to make estimates and judgments concerning transactions that will be settled several years in the future. Amounts recognized on the Consolidated Financial Statements based on such estimates involve numerous assumptions subject to varying and potentially significant degrees of judgment and uncertainty and will likely change in the future as additional information becomes available. The following critical accounting estimates are impacted significantly by PacifiCorp's methods, judgments and assumptions used in the preparation of the Consolidated Financial Statements and should be read in conjunction with PacifiCorp's Summary of Significant Accounting Policies included in Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Accounting for the Effects of Certain Types of Regulation

PacifiCorp prepares its financial statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, PacifiCorp defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in rates occur.

PacifiCorp continually evaluates the applicability of the guidance for regulated operations and whether its regulatory assets and liabilities are probable of inclusion in future rates by considering factors such as a change in the regulator's approach to setting rates from cost-based ratemaking to another form of regulation, other regulatory actions or the impact of competition that could limit PacifiCorp's ability to recover its costs. PacifiCorp believes its application of the guidance for regulated operations is appropriate and its existing regulatory assets and liabilities are probable of inclusion in future rates. The evaluation reflects the current political and regulatory climate at both the federal and state levels. If it becomes no longer probable that the deferred costs or income will be included in future rates, the related regulatory assets and liabilities will be recognized in net income, returned to customers or re-established as AOCI. Total regulatory assets were \$2.9 billion and total regulatory liabilities were \$2.6 billion as of December 31, 2024. Refer to Note 6 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding PacifiCorp's regulatory assets and liabilities.

Pension and Other Postretirement Benefits

PacifiCorp sponsors defined benefit pension and other postretirement benefit plans as described in Note 10. PacifiCorp recognizes the funded status of these defined benefit pension and other postretirement benefit plans on the Consolidated Balance Sheets. Funded status is the fair value of plan assets minus the benefit obligation as of the measurement date. As of December 31, 2024, PacifiCorp recognized a net asset totaling \$116 million for the funded status of its defined benefit pension and other postretirement benefit plans. As of December 31, 2024, amounts not yet recognized as a component of net periodic benefit cost (credit) included in net regulatory assets and accumulated other comprehensive loss totaled \$212 million and \$12 million, respectively.

The expense and benefit obligations relating to these defined benefit pension and other postretirement benefit plans are based on actuarial valuations. Inherent in these valuations are key assumptions, including, but not limited to, discount rate and expected long-term rate of return on plan assets. These key assumptions are reviewed annually and modified as appropriate. PacifiCorp believes that the key assumptions utilized in recording obligations under the plans are reasonable based on prior plan experience and current market and economic conditions. Refer to Note 10 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for disclosures about PacifiCorp's defined benefit pension and other postretirement benefit plans, including the key assumptions used to calculate the funded status and net periodic benefit cost for these plans as of and for the year ended December 31, 2024.

PacifiCorp chooses a discount rate based upon high quality debt security investment yields in effect as of the measurement date with cash flows aligning to the expected timing and amount of plan liabilities. The pension and other postretirement benefit liabilities increase as the discount rate is reduced.

In establishing its assumption as to the expected long-term rate of return on plan assets, PacifiCorp evaluates the investment allocation between return-seeking investment and fixed income securities based on the funded status of the plan and utilizes the asset allocation and return assumptions for each asset class based on forward-looking views of the financial markets and historical performance. Pension and other postretirement benefits expense increases as the expected long-term rate of return on plan assets decreases. PacifiCorp regularly reviews its actual asset allocations and rebalances its investments to its targeted allocations when considered appropriate.

The key assumptions used may differ materially from period to period due to changing market and economic conditions. These differences may result in a significant impact to pension and other postretirement benefits expense and funded status. If changes were to occur for the following key assumptions, the approximate effect on the Consolidated Financial Statements would be as follows (in millions):

	Pension Plans		Other Postretirement Benefit Plan	
	+0.5%	-0.5%	+0.5%	-0.5%
Effect on December 31, 2024 Benefit Obligations:				
Discount rate	\$ (22)	\$ 24	\$ (7)	\$ 7
Effect on 2024 Periodic Cost:				
Discount rate	\$ 1	\$ (1)	\$ —	\$ (1)
Expected rate of return on plan assets	(4)	4	(1)	1

A variety of factors affect the funded status of the plans, including discount rates, asset returns, mortality assumptions, plan changes and PacifiCorp's funding policy for each plan.

Income Taxes

In determining PacifiCorp's income taxes, management is required to interpret complex income tax laws and regulations, which includes consideration of regulatory implications imposed by PacifiCorp's various regulatory commissions. PacifiCorp's income tax returns are subject to continuous examinations by federal, state and local income tax authorities that may give rise to different interpretations of these complex laws and regulations. Due to the nature of the examination process, it generally takes years before these examinations are completed and these matters are resolved. PacifiCorp recognizes the tax benefit from an uncertain tax position only if it is more-likely-than-not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the Consolidated Financial Statements from such a position are measured based on the largest benefit that is more-likely-than-not to be realized upon ultimate settlement. Although the ultimate resolution of PacifiCorp's federal, state and local income tax examinations is uncertain, PacifiCorp believes it has made adequate provisions for these income tax positions. The aggregate amount of any additional income tax liabilities that may result from these examinations is not expected to have a material impact on PacifiCorp's consolidated financial results. Refer to Note 9 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding PacifiCorp's income taxes.

It is probable that PacifiCorp will pass income tax benefit and expense related to the federal tax rate change from 35% to 21%, certain property-related basis differences and other various differences on to customers in certain state jurisdictions. As of December 31, 2024, these amounts were recognized as a net regulatory liability of \$861 million and will primarily be included in regulated rates over the estimated useful lives of the related properties.

PacifiCorp is required to evaluate its exposure to potential loss contingencies arising from claims associated with the Wildfires. In determining this exposure, PacifiCorp is required to assess whether the likelihood of loss associated with the Wildfires is remote, reasonably possible or probable, which involves complex judgments based on several variables including available information regarding the cause and origin of the wildfires, investigations, discovery associated with lawsuits and negotiations with various parties, including mediation and settlement discussions. If deemed reasonably possible, PacifiCorp is required to estimate the potential loss or range of potential loss and disclose any material amounts. If deemed probable, PacifiCorp is required to accrue a loss if reasonably estimable based on the bottom end of the range if no amount within the range of estimated loss is any better than another amount. Many assumptions and variables are involved in determining these estimates, including identifying the various categories of potential loss such as fire suppression costs, real and personal property damages, natural resource damages for certain areas and noneconomic damages such as personal injury damages and loss of life damages. Within the categories of potential loss, further assumptions are made regarding items such as the types of structures damaged, estimated replacement values associated with those structures, value of personal property, the types of natural resource damage such as timber, the value of that timber, the nature of noneconomic damages such as those arising from personal injuries, other damages PacifiCorp may be responsible for if found negligent such as punitive damages, and the amount of any penalties or fines that may be imposed by governmental entities. Refer to Note 14 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding PacifiCorp's loss contingencies associated with the Wildfires.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

PacifiCorp's Consolidated Balance Sheets include assets and liabilities with fair values that are subject to market risks. PacifiCorp's significant market risks are primarily associated with commodity prices, interest rates and the extension of credit to counterparties with which PacifiCorp transacts. The following discussion addresses the significant market risks associated with PacifiCorp's business activities. PacifiCorp has established guidelines for credit risk management. Refer to Notes 2 and 12 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding PacifiCorp's contracts accounted for as derivatives.

PacifiCorp has a risk management committee that is responsible for the oversight of market and credit risk relating to the commodity transactions of PacifiCorp. To limit PacifiCorp's exposure to market and credit risk, the risk management committee recommends, and executive management establishes, policies, limits and approved products, which are reviewed frequently to respond to changing market conditions.

Risk is an inherent part of PacifiCorp's business and activities. PacifiCorp has established a risk management process that is designed to identify, assess, manage and report on each of the various types of risk involved in its business. The risk management policy governs energy transactions and is designed for hedging PacifiCorp's existing energy and asset exposures, and to a limited extent, the policy permits arbitrage and trading activities to take advantage of market inefficiencies. The policy also governs the types of transactions authorized for use and establishes guidelines for credit risk management and management information systems required to effectively monitor such transactions. PacifiCorp's risk management policy provides for the use of only those contracts that have a similar volume or price relationship to its portfolio of assets, liabilities or anticipated transactions.

PacifiCorp has controls and procedures in place to monitor compliance with its risk management policy and limit procedures on a regular and on-going basis, including remediation procedures in the event of an incident of non-compliance to the policy.

Commodity Price Risk

PacifiCorp is principally exposed to electricity, natural gas, coal and fuel oil commodity price risk as it has an obligation to serve retail customer load in its service territories. PacifiCorp's load and generating facilities represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel required to generate electricity and wholesale electricity that is purchased and sold. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather, market liquidity, generating facility availability, customer usage, storage, and transmission and transportation constraints. PacifiCorp does not engage in a material amount of proprietary trading activities. To mitigate a portion of its commodity price risk, PacifiCorp uses commodity derivative contracts, which may include forwards, futures, options, swaps and other agreements, to effectively secure future supply or sell future production generally at fixed prices. PacifiCorp does not hedge all of its commodity price risk, thereby exposing the unhedged portion to changes in market prices. PacifiCorp's exposure to commodity price risk is generally limited by its ability to include commodity costs in rates, which is subject to regulatory lag that occurs between the time the costs are incurred and when the costs are included in rates, as well as the impact of any customer sharing resulting from cost adjustment mechanisms.

PacifiCorp measures, monitors and manages the market risk in its electricity and natural gas portfolio in comparison to established thresholds and measures its open positions subject to price risk in terms of quantity at each delivery location for each forward time period. PacifiCorp has a risk management policy that requires increasing volumes of hedge transactions over a three-year position management and hedging horizon to reduce market risk of its electricity and natural gas portfolio.

The table that follows summarizes PacifiCorp's price risk on commodity contracts accounted for as derivatives, excluding net collateral receivable of \$6 million and \$10 million as of December 31, 2024 and 2023, respectively, and shows the effects of a hypothetical 10% increase and 10% decrease in forward market prices by the expected volumes for these contracts as of that date. The selected hypothetical change does not reflect what could be considered the best or worst case scenarios (dollars in millions):

	Fair Value - Net (Liability) Asset	Estimated Fair Value after Hypothetical Change in Price	
		10% increase	10% decrease
<u>As of December 31, 2024:</u>			
Total commodity derivative contracts	\$ (97)	\$ (56)	\$ (138)
<u>As of December 31, 2023:</u>			
Total commodity derivative contracts	\$ (76)	\$ 13	\$ (165)

PacifiCorp's commodity derivative contracts are generally recoverable from customers in rates; therefore, net unrealized gains and losses associated with interim price movements on commodity derivative contracts do not expose PacifiCorp to earnings volatility. As of December 31, 2024 and 2023, a regulatory asset of \$97 million and \$76 million, respectively, was recorded related to the net derivative liability of \$97 million and \$76 million, respectively.

Interest Rate Risk

PacifiCorp is exposed to interest rate risk on its outstanding variable-rate short- and long-term debt and future debt issuances. PacifiCorp manages its interest rate risk by limiting its exposure to variable interest rates primarily through the issuance of fixed-rate long-term debt and by monitoring market changes in interest rates. As a result of the fixed interest rates, PacifiCorp's fixed-rate long-term debt does not expose PacifiCorp to the risk of loss due to changes in market interest rates. Additionally, because fixed-rate long-term debt is not carried at fair value on the Consolidated Balance Sheets, changes in fair value would impact earnings and cash flows only if PacifiCorp were to reacquire all or a portion of these instruments prior to their maturity. PacifiCorp has the ability to enter into interest rate derivative contracts, such as interest rate swaps or locks, to mitigate PacifiCorp's exposure to interest rate risk. The nature and amount of PacifiCorp's short- and long-term debt can be expected to vary from period to period as a result of future business requirements, market conditions and other factors. Refer to Notes 7, 8 and 13 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional discussion of PacifiCorp's short- and long-term debt.

As of December 31, 2024 and 2023, PacifiCorp had short- and long-term variable-rate obligations totaling \$292 million and \$1.8 billion, respectively, that expose PacifiCorp to the risk of increased interest expense in the event of increases in short-term interest rates. The market risk related to PacifiCorp's variable-rate debt as of December 31, 2024 is not hedged. If variable interest rates were to increase by 10% from December 31 levels, it would not have a material effect on PacifiCorp's consolidated annual interest expense. The carrying value of the variable-rate obligations approximates fair value as of December 31, 2024 and 2023.

Credit Risk

PacifiCorp is exposed to counterparty credit risk associated with wholesale energy supply and marketing activities with other utilities, energy marketing companies, financial institutions and other market participants. Credit risk may be concentrated to the extent PacifiCorp's counterparties have similar economic, industry or other characteristics and due to direct or indirect relationships among the counterparties. Before entering into a transaction, PacifiCorp analyzes the financial condition of each significant wholesale counterparty, establishes limits on the amount of unsecured credit to be extended to each counterparty and evaluates the appropriateness of unsecured credit limits on an ongoing basis. To further mitigate wholesale counterparty credit risk, PacifiCorp enters into netting and collateral arrangements that may include margining and cross-product netting agreements and obtains third-party guarantees, letters of credit and cash deposits. If required, PacifiCorp exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

As of December 31, 2024, PacifiCorp's aggregate credit exposure with wholesale energy supply and marketing counterparties included counterparties having non-investment grade, internally rated credit ratings. Substantially all of these non-investment grade, internally rated counterparties are associated with long-duration solar and wind power purchase agreements, some of which are from facilities that have not yet achieved commercial operation and for which PacifiCorp has no obligation should the facilities not achieve commercial operation.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of PacifiCorp

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of PacifiCorp and subsidiaries ("PacifiCorp") as of December 31, 2024 and 2023, the related consolidated statements of operations, comprehensive (loss) income, changes in shareholders' equity, and cash flows, for each of the three years in the period ended December 31, 2024, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of PacifiCorp as of December 31, 2024 and 2023, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2024, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of PacifiCorp's management. Our responsibility is to express an opinion on PacifiCorp's financial statements 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 PacifiCorp 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. PacifiCorp is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of PacifiCorp's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the 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 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 financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current-period audit of the financial statements that were communicated or required to be communicated to the executive committee and that (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Regulatory Matters — Effects of Rate Regulation on the Financial Statements — Refer to Note 6 to the financial statements

Critical Audit Matter Description

PacifiCorp is subject to rate regulation by the Federal Energy Regulatory Commission as well as certain other regulatory commissions (collectively, the "Commissions"), which have jurisdiction with respect to the rates of electric and natural gas companies in the respective service territories where PacifiCorp operates. Management has determined its regulated operations meet the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the specialized rules to account for the effects of cost-based rate regulation. Accounting for the economic effects of rate regulation has a pervasive effect on the financial statements.

Regulated rates are subject to regulatory rate-setting processes. Rates are determined, approved, and established based on a cost-of-service basis, which is designed to allow PacifiCorp an opportunity to recover its prudently incurred costs of providing services and to earn a reasonable return on its invested capital. Regulatory decisions can have an effect on the recovery of costs, the rate of return earned on investment, and the timing and amount of assets to be recovered by rates. While PacifiCorp has indicated it expects to recover costs from customers through regulated rates, there is a risk that changes to the Commissions' approach to setting rates or other regulatory actions could limit PacifiCorp's ability to recover its costs.

We identified the effects of rate regulation on the financial statements as a critical audit matter due to the significant judgments made by management to support its assertions about certain affected account balances and disclosures and the high degree of subjectivity involved in assessing the impact of regulatory orders on the financial statements. Management judgments include assessing the likelihood of (1) recovery in future rates of incurred costs, (2) a disallowance of part of the cost of recently completed plant or plant under construction, and (3) refunds to customers. Given that management's accounting judgments are based on assumptions about the outcome of decisions by the Commissions, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate setting process due to its inherent complexities.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the uncertainty of decisions by the Commissions included the following, among others:

- We evaluated PacifiCorp's disclosures related to the effects of rate regulation by testing certain recorded balances and evaluating regulatory developments.
- We read relevant regulatory orders issued by the Commissions, regulatory statutes, filings made by PacifiCorp and intervenors, and other external information. We evaluated relevant external information and compared it to certain recorded regulatory asset and liability balances for completeness.
- For certain regulatory matters, we inspected PacifiCorp's filings with the Commissions and the filings with the Commissions by intervenors to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedents of the Commissions' treatment of similar costs under similar circumstances.

Wildfires — Contingencies — Refer to Note 14 to the financial statements

Critical Audit Matter Description

As a result of several wildfires that have occurred in PacifiCorp's service territory and surrounding areas in Oregon and California, PacifiCorp is required to evaluate its exposure to potential loss contingencies arising from claims associated with the 2020 Wildfires and the 2022 McKinney Fire (the "Wildfires"). In determining this exposure, PacifiCorp is required to determine whether the likelihood of loss for each of the Wildfires is remote, reasonably possible or probable, which involves complex judgments based on several variables including available information regarding the cause and origin of the Wildfires, investigations, discovery associated with lawsuits and negotiations with claimants.

A provision for a loss contingency is recorded when it is probable that a liability has been incurred and the amount of loss can be reasonably estimated. If deemed reasonably possible, PacifiCorp is required to estimate and disclose the potential loss or range of potential loss.

Management has recorded estimated liabilities which represent its best estimate of probable losses associated with the Wildfires.

We identified wildfire-related contingencies and the related disclosures as a critical audit matter because of the significant judgments made by management to determine the probability of loss and estimate the probable losses. Auditing the reasonableness of management's judgments, estimates and disclosures related to wildfire-related loss contingencies required the application of a high degree of judgment and extensive effort.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to management's judgments regarding the probability of loss, estimated losses, and related disclosures for wildfire-related contingencies included the following, among others:

- We evaluated management's judgments related to whether a loss was remote, reasonably possible, or probable for the Wildfires by inquiring of management and PacifiCorp's external and internal legal counsel regarding the likelihood of loss and amounts of probable and reasonably possible losses. We also evaluated the potential impact of information gained through PacifiCorp and third-parties' investigations into the cause of the fires, information from claimants, the advice of legal counsel, and reading external information for any evidence that might contradict management's assertions.
- We evaluated the estimation methodology for determining the amount of probable and reasonably possible losses through inquiries with management and external and internal legal counsel, and we tested the significant assumptions, including certain settlements, used in the estimates of probable and reasonably possible losses.
- We read legal letters from PacifiCorp's external and internal legal counsel regarding known information and evaluated whether the information therein was consistent with the information obtained in our procedures.
- We evaluated whether PacifiCorp's disclosures were appropriate and consistent with the information obtained in our procedures.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 21, 2025

We have served as PacifiCorp's auditor since 2006.

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Amounts in millions)

	As of December 31,	
	2024	2023
ASSETS		
Current assets:		
Cash and cash equivalents	\$ 46	\$ 138
Trade receivables, net	960	853
Other receivables, net	245	447
Inventories	828	532
Derivative contracts	9	16
Regulatory assets	891	631
Prepaid expenses	283	188
Other current assets	35	182
Total current assets	3,297	2,987
Property, plant and equipment, net	29,120	27,051
Regulatory assets	2,026	1,942
Other assets	561	630
Total assets	\$ 35,004	\$ 32,610

The accompanying notes are an integral part of these consolidated financial statements.

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (continued)
(Amounts in millions)

	As of December 31,	
	2024	2023
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	\$ 1,462	\$ 1,560
Accrued interest	239	152
Accrued property, income and other taxes	85	65
Accrued employee expenses	96	93
Short-term debt	240	1,604
Current portion of long-term debt	302	591
Regulatory liabilities	92	70
Wildfires liabilities (Note 14)	247	4
Other current liabilities	466	437
Total current liabilities	3,229	4,576
Long-term debt	13,286	9,819
Regulatory liabilities	2,550	2,540
Deferred income taxes	3,222	3,085
Wildfires liabilities (Note 14)	1,289	1,719
Other long-term liabilities	916	899
Total liabilities	24,492	22,638
Commitments and contingencies (Note 14)		
Shareholders' equity:		
Preferred stock	2	2
Common stock - 750 shares authorized, no par value, 357 shares issued and outstanding	—	—
Additional paid-in capital	4,479	4,479
Retained earnings	6,040	5,501
Accumulated other comprehensive loss, net	(9)	(10)
Total shareholders' equity	10,512	9,972
Total liabilities and shareholders' equity	\$ 35,004	\$ 32,610

The accompanying notes are an integral part of these consolidated financial statements.

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2024	2023	2022
Operating revenue	\$ 6,600	\$ 5,936	\$ 5,679
Operating expenses:			
Cost of fuel and energy	2,752	2,246	1,979
Operations and maintenance	1,603	1,469	1,163
Wildfires losses, net of recoveries (Note 14)	346	1,677	64
Depreciation and amortization	1,152	1,126	1,120
Property and other taxes	218	215	195
Total operating expenses	6,071	6,733	4,521
Operating income (loss)	529	(797)	1,158
Other income (expense):			
Interest expense	(756)	(546)	(431)
Allowance for borrowed funds	120	70	31
Allowance for equity funds	203	144	71
Interest and dividend income	191	98	44
Other, net	16	10	(15)
Total other income (expense)	(226)	(224)	(300)
Income (loss) before income tax expense (benefit)	303	(1,021)	858
Income tax expense (benefit)	(236)	(553)	(62)
Net income (loss)	\$ 539	\$ (468)	\$ 920

The accompanying notes are an integral part of these consolidated financial statements.

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(Amounts in millions)

	Years Ended December 31,		
	2024	2023	2022
Net income (loss)	\$ 539	\$ (468)	\$ 920
Other comprehensive income (loss), net of tax —			
Unrecognized amounts on retirement benefits, net of tax of \$—, \$— and \$3	1	(1)	8
Comprehensive income (loss)	<u>\$ 540</u>	<u>\$ (469)</u>	<u>\$ 928</u>

The accompanying notes are an integral part of these consolidated financial statements.

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
(Amounts in millions)

	Preferred Stock	Common Stock	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss, Net	Total Shareholders' Equity
Balance, December 31, 2021	\$ 2	\$ —	\$ 4,479	\$ 5,449	\$ (17)	\$ 9,913
Net income	—	—	—	920	—	920
Other comprehensive income	—	—	—	—	8	8
Common stock dividends declared	—	—	—	(100)	—	(100)
Balance, December 31, 2022	2	—	4,479	6,269	(9)	10,741
Net loss	—	—	—	(468)	—	(468)
Other comprehensive loss	—	—	—	—	(1)	(1)
Common stock dividends declared	—	—	—	(300)	—	(300)
Balance, December 31, 2023	2	—	4,479	5,501	(10)	9,972
Net income	—	—	—	539	—	539
Other comprehensive income	—	—	—	—	1	1
Balance, December 31, 2024	<u>\$ 2</u>	<u>\$ —</u>	<u>\$ 4,479</u>	<u>\$ 6,040</u>	<u>\$ (9)</u>	<u>\$ 10,512</u>

The accompanying notes are an integral part of these consolidated financial statements.

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Amounts in millions)

	Years Ended December 31,		
	2024	2023	2022
Cash flows from operating activities:			
Net income (loss)	\$ 539	\$ (468)	\$ 920
Adjustments to reconcile net income (loss) to net cash flows from operating activities:			
Depreciation and amortization	1,152	1,126	1,120
Allowance for equity funds	(203)	(144)	(71)
Net power cost deferrals	(646)	(760)	(482)
Amortization of net power cost deferrals	556	231	100
Other changes in regulatory assets and liabilities	(146)	(161)	(162)
Deferred income taxes and amortization of investment tax credits	(9)	(224)	157
Other, net	18	11	13
Changes in other operating assets and liabilities:			
Trade receivables, other receivables and other assets	(81)	(38)	(88)
Inventories	(296)	(58)	—
Prepaid expenses	(100)	(91)	(46)
Derivative collateral, net	4	(100)	95
Accrued property, income and other taxes, net	132	(40)	(46)
Accounts payable and other liabilities	23	370	267
Wildfires insurance receivable	401	(253)	(130)
Wildfires liability	(187)	1,299	172
Net cash flows from operating activities	<u>1,157</u>	<u>700</u>	<u>1,819</u>
Cash flows from investing activities:			
Capital expenditures	(3,102)	(3,226)	(2,166)
Other, net	11	5	5
Net cash flows from investing activities	<u>(3,091)</u>	<u>(3,221)</u>	<u>(2,161)</u>
Cash flows from financing activities:			
Proceeds from long-term debt	3,762	1,189	1,087
Repayments of long-term debt	(591)	(449)	(155)
Net (repayments of) proceeds from short-term debt	(1,364)	1,604	—
Dividends paid	—	(300)	(100)
Other, net	(4)	(5)	(2)
Net cash flows from financing activities	<u>1,803</u>	<u>2,039</u>	<u>830</u>
Net change in cash and cash equivalents and restricted cash and cash equivalents	(131)	(482)	488
Cash and cash equivalents and restricted cash and cash equivalents at beginning of period	192	674	186
Cash and cash equivalents and restricted cash and cash equivalents at end of period	<u>\$ 61</u>	<u>\$ 192</u>	<u>\$ 674</u>

The accompanying notes are an integral part of these consolidated financial statements.

PACIFICORP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Organization and Operations

PacifiCorp, which includes PacifiCorp and its subsidiaries, is a U.S. regulated electric utility company serving retail customers, including residential, commercial, industrial, irrigation and other customers in portions of Utah, Oregon, Wyoming, Washington, Idaho and California. PacifiCorp owns, or has interests in, a number of thermal, hydroelectric, wind-powered and geothermal generating facilities, as well as electric transmission and distribution assets. PacifiCorp also buys and sells electricity on the wholesale market with other utilities, energy marketing companies, financial institutions and other market participants. PacifiCorp is subject to comprehensive state and federal regulation. PacifiCorp's subsidiaries support its electric utility operations by providing coal mining services. PacifiCorp is an indirect subsidiary of Berkshire Hathaway Energy Company ("BHE"), a holding company based in Des Moines, Iowa that has investments in subsidiaries principally engaged in energy businesses. BHE is a wholly owned subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway").

(2) Summary of Significant Accounting Policies

Basis of Consolidation and Presentation

The Consolidated Financial Statements include the accounts of PacifiCorp and its subsidiaries in which it holds a controlling financial interest as of the financial statement date. Intercompany accounts and transactions have been eliminated.

Use of Estimates in Preparation of Financial Statements

The preparation of the Consolidated Financial Statements in conformity with accounting principles generally accepted in the United States of America ("GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the period. These estimates include, but are not limited to, the effects of regulation; certain assumptions made in accounting for pension and other postretirement benefits; asset retirement obligations ("AROs"); income taxes; unbilled revenue; valuation of certain financial assets and liabilities, including derivative contracts; and accounting for loss contingencies and applicable insurance recoveries, including those related to the Oregon and Northern California 2020 wildfires (the "2020 Wildfires") and a wildfire that began in the Oak Knoll Ranger District of the Klamath National Forest in Siskiyou County, California in July 2022 (the "2022 McKinney Fire"), referred to together as "the Wildfires" as discussed in Note 14. Actual results may differ from the estimates used in preparing the Consolidated Financial Statements.

Accounting for the Effects of Certain Types of Regulation

PacifiCorp prepares its financial statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, PacifiCorp defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in rates occur.

If it becomes no longer probable that the deferred costs or income will be included in future rates, the related regulatory assets and liabilities will be recognized in net income, returned to customers or re-established as accumulated other comprehensive income (loss) ("AOCI").

Fair Value Measurements

As defined under GAAP, fair value is the price that would be received to sell an asset or paid to transfer a liability between market participants in the principal market or in the most advantageous market when no principal market exists. Adjustments to transaction prices or quoted market prices may be required in illiquid or disorderly markets in order to estimate fair value. Different valuation techniques may be appropriate under the circumstances to determine the value that would be received to sell an asset or paid to transfer a liability in an orderly transaction. Market participants are assumed to be independent, knowledgeable, able and willing to transact an exchange and not under duress. Nonperformance or credit risk is considered when determining fair value. Considerable judgment may be required in interpreting market data used to develop the estimates of fair value. Accordingly, estimates of fair value presented herein are not necessarily indicative of the amounts that could be realized in a current or future market exchange.

Cash and Cash Equivalents and Restricted Cash and Cash Equivalents

Cash equivalents consist of funds invested in money market mutual funds, U.S. Treasury Bills and other investments with a maturity of three months or less when purchased. Cash and cash equivalents exclude amounts where availability is restricted by legal requirements, loan agreements or other contractual provisions. Restricted cash and cash equivalents consist substantially of funds representing vendor retention, nuclear decommissioning and custodial funds. A reconciliation of cash and cash equivalents and restricted cash and cash equivalents as of December 31, 2024 and 2023 as presented on the Consolidated Statements of Cash Flows is outlined below and disaggregated by the line items in which they appear on the Consolidated Balance Sheets (in millions):

	As of December 31,	
	2024	2023
Cash and cash equivalents	\$ 46	\$ 138
Restricted cash included in other current assets	12	51
Restricted cash included in other assets	3	3
Total cash and cash equivalents and restricted cash and cash equivalents	<u>\$ 61</u>	<u>\$ 192</u>

Investments

Available-for-sale securities are carried at fair value with realized gains and losses, as determined on a specific identification basis, recognized in earnings and unrealized gains and losses recognized in AOCI, net of tax. As of December 31, 2024 and 2023, PacifiCorp had no unrealized gains and losses on available-for-sale securities. Trading securities are carried at fair value with realized and unrealized gains and losses recognized in earnings.

Equity Method Investments

PacifiCorp utilizes the equity method of accounting with respect to investments when it possesses the ability to exercise significant influence, but not control, over the operating and financial policies of the investee. The ability to exercise significant influence is presumed when an investor possesses more than 20% of the voting interests of the investee. This presumption may be overcome based on specific facts and circumstances that demonstrate that the ability to exercise significant influence is restricted. In applying the equity method, PacifiCorp records the investment at cost and subsequently increases or decreases the carrying value of the investment by PacifiCorp's proportionate share of the net earnings or losses and other comprehensive income (loss) ("OCI") of the investee. PacifiCorp records dividends or other equity distributions as reductions in the carrying value of the investment.

Allowance for Credit Losses

Trade receivables are primarily short-term in nature with stated collection terms of less than one year from the date of origination, and are stated at the outstanding principal amount, net of an estimated allowance for credit losses. The allowance for credit losses is based on PacifiCorp's assessment of the collectability of amounts owed to PacifiCorp by its customers. This assessment requires judgment regarding the ability of customers to pay or the outcome of any pending disputes. In measuring the allowance for credit losses for trade receivables, PacifiCorp primarily utilizes credit loss history. However, PacifiCorp may adjust the allowance for credit losses to reflect current conditions and reasonable and supportable forecasts that deviate from historical experience. The changes in the balance of the allowance for credit losses, which is included in trade receivables, net on the Consolidated Balance Sheets, is summarized as follows for the years ended December 31 (in millions):

	2024	2023	2022
Beginning balance	\$ 30	\$ 19	\$ 18
Charged to operating costs and expenses, net	26	34	18
Write-offs, net	(34)	(23)	(17)
Ending balance	<u>\$ 22</u>	<u>\$ 30</u>	<u>\$ 19</u>

Derivatives

PacifiCorp employs a number of different derivative contracts, which may include forwards, options, swaps and other agreements, to manage price risk for electricity, natural gas and other commodities and interest rate risk. Derivative contracts are recorded on the Consolidated Balance Sheets as either assets or liabilities and are stated at estimated fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by GAAP. Derivative balances reflect offsetting permitted under master netting agreements with counterparties and cash collateral paid or received under such agreements.

Commodity derivatives used in normal business operations that are settled by physical delivery, among other criteria, are eligible for and may be designated as normal purchases or normal sales. Normal purchases or normal sales contracts are not marked-to-market and settled amounts are recognized as operating revenue or cost of fuel and energy on the Consolidated Statements of Operations.

For PacifiCorp's derivative contracts, the settled amount is generally included in rates. Accordingly, the net unrealized gains and losses associated with interim price movements on contracts that are accounted for as derivatives and probable of inclusion in rates are recorded as regulatory liabilities or assets. For a derivative contract not probable of inclusion in rates, changes in the fair value are recognized in earnings.

Inventories

Inventories consist mainly of materials, supplies and fuel stocks and are stated at the lower of average cost or net realizable value.

Property, Plant and Equipment, Net

General

Additions to property, plant and equipment are recorded at cost. PacifiCorp capitalizes all construction-related material, direct labor and contract services, as well as indirect construction costs, which include debt and equity allowance for funds used during construction ("AFUDC"). The cost of additions and betterments are capitalized, while costs incurred that do not improve or extend the useful lives of the related assets are generally expensed.

Depreciation and amortization are generally computed on the straight-line method based on composite asset class lives prescribed by PacifiCorp's various regulatory authorities or over the assets' estimated useful lives. Depreciation studies are completed periodically to determine the appropriate composite asset class lives, net salvage and depreciation rates. These studies are reviewed and rates are ultimately approved by the various regulatory authorities. Net salvage includes the estimated future residual values of the assets and any estimated removal costs recovered through approved depreciation rates. Estimated removal costs are recorded as either a cost of removal regulatory liability or an ARO liability on the Consolidated Balance Sheets, depending on whether the obligation meets the requirements of an ARO. As actual removal costs are incurred, the associated liability is reduced.

Generally when PacifiCorp retires or sells a component of regulated property, plant and equipment, it charges the original cost, net of any proceeds from the disposition, to accumulated depreciation. Any gain or loss on disposals of all other assets is recorded through earnings.

Debt and equity AFUDC, which represents the estimated costs of debt and equity funds necessary to finance the construction of property, plant and equipment, is capitalized as a component of property, plant and equipment, with offsetting credits to the Consolidated Statements of Operations. AFUDC is computed based on guidelines set forth by the Federal Energy Regulatory Commission ("FERC"). After construction is completed, PacifiCorp is permitted to earn a return on these costs as a component of the related assets, as well as recover these costs through depreciation expense over the useful lives of the related assets.

Asset Retirement Obligations

PacifiCorp recognizes AROs when it has a legal obligation to perform decommissioning, reclamation or removal activities upon retirement of an asset. PacifiCorp's AROs are primarily associated with its generating facilities. The fair value of an ARO liability is recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made, and is added to the carrying amount of the associated asset, which is then depreciated over the remaining useful life of the asset. Subsequent to the initial recognition, the ARO liability is adjusted for any revisions to the original estimate of undiscounted cash flows (with corresponding adjustments to property, plant and equipment, net) and for accretion of the ARO liability due to the passage of time. The difference between the ARO liability, the corresponding ARO asset included in property, plant and equipment, net and amounts recovered in rates to satisfy such liabilities is recorded as a regulatory asset or liability.

Impairment

PacifiCorp evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or when the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value and any resulting impairment loss is reflected on the Consolidated Statements of Operations. As substantially all property, plant and equipment supports PacifiCorp's regulated operations, the impacts of regulation are considered when evaluating the carrying value of regulated assets.

Leases

PacifiCorp has non-cancelable operating leases primarily for land, office space, office equipment, and generating facilities and finance leases consisting primarily of office buildings, natural gas pipeline facilities, and vehicles. These leases generally require PacifiCorp to pay for insurance, taxes and maintenance applicable to the leased property. Given the capital-intensive nature of the utility industry, it is common for a portion of lease costs to be capitalized when used during construction or maintenance of assets, in which the associated costs will be capitalized with the corresponding asset and depreciated over the remaining life of that asset. Certain leases contain renewal options for varying periods and escalation clauses for adjusting rent to reflect changes in price indices. PacifiCorp does not include options in its lease calculations unless there is a triggering event indicating PacifiCorp is reasonably certain to exercise the option. PacifiCorp's accounting policy is to not recognize right-of-use assets and lease obligations for leases with contract terms of one year or less and not separate lease components from non-lease components and instead account for each separate lease component and the non-lease components associated with a lease as a single lease component. Right-of-use assets will be evaluated for impairment in line with Accounting Standards Codification ("ASC") 360, "Property, Plant and Equipment" when a triggering event has occurred that might affect the value and use of the assets being leased.

PacifiCorp's leases of generating facilities generally are in the form of long-term purchases of electricity, also known as power purchase agreements ("PPA"). PPAs are generally signed before or during the early stages of project construction and can yield a lease that has not yet commenced. These agreements are primarily for renewable energy and the payments are considered variable lease payments as they are based on the amount of output.

PacifiCorp's operating and finance right-of-use assets are recorded in other assets and the operating and finance lease liabilities are recorded in current and long-term other liabilities accordingly.

Revenue Recognition

PacifiCorp uses a single five-step model to identify and recognize revenue from contracts with customers ("Customer Revenue") upon transfer of control of promised goods or services in an amount that reflects the consideration to which PacifiCorp expects to be entitled in exchange for those goods or services. PacifiCorp records sales, franchise and excise taxes collected directly from customers and remitted directly to the taxing authorities on a net basis on the Consolidated Statements of Operations.

Substantially all of PacifiCorp's Customer Revenue is derived from tariff-based sales arrangements approved by various regulatory commissions. These tariff-based revenues are mainly comprised of energy, transmission and distribution and have performance obligations to deliver energy products and services to customers which are satisfied over time as energy is delivered or services are provided.

Revenue recognized is equal to what PacifiCorp has the right to invoice as it corresponds directly with the value to the customer of PacifiCorp's performance to date and includes billed and unbilled amounts. Payments for amounts billed are generally due from the customer within 30 days of billing. Rates charged for energy products and services are established by regulators or contractual arrangements that establish the transaction price as well as the allocation of price amongst the separate performance obligations. When preliminary regulated rates are permitted to be billed prior to final approval by the applicable regulator, certain revenue collected may be subject to refund and a liability for estimated refunds is accrued.

The determination of customer billings is based on a systematic reading of meters. At the end of each month, energy provided to customers since the date of the last meter reading is estimated, and the corresponding unbilled revenue is recorded. Factors that can impact the estimate of unbilled energy include, but are not limited to, seasonal weather patterns, total volumes supplied to the system, line losses, economic impacts and composition of sales among customer classes. Unbilled revenue is reversed in the following month and billed revenue is recorded based on the subsequent meter readings.

As of December 31, 2024 and 2023, trade receivables, net on the Consolidated Balance Sheets relate substantially to Customer Revenue, including unbilled revenue of \$329 million and \$296 million, respectively.

Unamortized Debt Premiums, Discounts and Debt Issuance Costs

Premiums, discounts and debt issuance costs incurred for the issuance of long-term debt are amortized over the term of the related financing using the effective interest method.

Income Taxes

Berkshire Hathaway includes PacifiCorp in its consolidated U.S. federal income tax return. Consistent with established regulatory practice, PacifiCorp's provision for income taxes has been computed on a stand-alone basis.

Deferred income tax assets and liabilities are based on differences between the financial statement and income tax basis of assets and liabilities using enacted income tax rates expected to be in effect for the year in which the differences are expected to reverse. Changes in deferred income tax assets and liabilities associated with components of OCI are charged or credited directly to OCI. Changes in deferred income tax assets and liabilities associated with certain property-related basis differences and other various differences that PacifiCorp deems probable to be passed on to its customers in most state jurisdictions are charged or credited directly to a regulatory asset or liability and will be included in regulated rates when the temporary differences reverse or as otherwise approved by PacifiCorp's various regulatory commissions. Other changes in deferred income tax assets and liabilities are included as a component of income tax expense. Changes in deferred income tax assets and liabilities attributable to changes in enacted income tax rates are charged or credited to income tax expense or a regulatory asset or liability in the period of enactment. Valuation allowances are established when necessary to reduce deferred income tax assets to the amount that is more-likely-than-not to be realized.

Investment tax credits are deferred and amortized over the estimated useful lives of the related properties or as prescribed by various regulatory commissions.

PacifiCorp recognizes the tax benefit from an uncertain tax position only if it is more-likely-than-not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the Consolidated Financial Statements from such a position are measured based on the largest benefit that is more-likely-than-not to be realized upon ultimate settlement. PacifiCorp's unrecognized tax benefits are primarily included in other long-term liabilities on the Consolidated Balance Sheets. Estimated interest and penalties, if any, related to uncertain tax positions are included as a component of income tax expense (benefit) on the Consolidated Statements of Operations.

Government Grants

From time to time, PacifiCorp enters into grant agreements with federal agencies, as well as agreements with third parties as a subrecipient of a federal grant, subjecting PacifiCorp to various federal compliance requirements. Most commonly these are cost share grants where PacifiCorp expenditures match the amount of grant proceeds. Grant proceeds most frequently support capital projects but are also used to cover operating costs. Grant proceeds received to reimburse capital project costs are applied as a direct offset to construction work-in-progress, ultimately serving to reduce PacifiCorp's investment in property, plant and equipment. Grant proceeds received to reimburse operating costs are applied as an offset to operating expense.

Segment Information

PacifiCorp currently has one reportable segment, its regulated electric utility operations, which derives its revenue from regulated retail sales of electricity to residential, commercial, industrial and irrigation customers and from wholesale sales. PacifiCorp's chief operating decision maker ("CODM") is its Chief Executive Officer. The CODM uses net income, as reported on the Consolidated Statements of Operations, and generally considers actual results versus historical results, budgets or forecasts, as well as unique risks and opportunities, when making decisions about the allocation of resources and capital. The segment expenses regularly provided to the CODM align with the captions presented on the Consolidated Statements of Operations. PacifiCorp's segment capital expenditures are reported on the Consolidated Statements of Cash Flows as capital expenditures. PacifiCorp's segment assets are reported on the Consolidated Balance Sheet as total assets.

New Accounting Pronouncements

In November 2023, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2023-07, Segment Reporting Topic 280, "Segment Reporting—Improvements to Reportable Segment Disclosures" which allows disclosure of one or more measures of segment profit or loss used by the chief operating decision maker to allocate resources and assess performance. Additionally, the standard requires enhanced disclosures of significant segment expenses and other segment items as well as incremental qualitative disclosures on both an annual and interim basis. This guidance is effective for annual reporting periods beginning after December 15, 2023, and interim reporting periods after December 15, 2024. Early adoption is permitted and retrospective application is required for all periods presented. PacifiCorp adopted this guidance for the fiscal year beginning January 1, 2024 under the retrospective method. The adoption did not have a material impact on PacifiCorp's Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

In December 2023, the FASB issued ASU No. 2023-09, Income Taxes Topic 740, "Income Tax—Improvements to Income Tax Disclosures" which requires enhanced disclosures, including specific categories and disaggregation of information in the effective tax rate reconciliation, disaggregated information related to income taxes paid, income or loss from continuing operations before income tax expense or benefit, and income tax expense or benefit from continuing operations. This guidance is effective for annual reporting periods beginning after December 15, 2024. Early adoption is permitted and should be applied on a prospective basis, however retrospective application is permitted. PacifiCorp is currently evaluating the impact of adopting this guidance on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

In November 2024, the FASB issued ASU No. 2024-03, Income Statement—Reporting Comprehensive Income—Expense Disaggregation Disclosures Subtopic 220-40, "Disaggregation of Income Statement Expenses" which addresses requests from investors for more detailed information about certain expenses and requires disclosure of the amounts of purchases of inventory, employee compensation, depreciation and intangible asset amortization included in each relevant expense caption presented on the income statement. This guidance is effective for annual reporting periods beginning after December 15, 2026 and interim reporting periods beginning after December 15, 2027. Early adoption is permitted and should be applied on a prospective basis, however retrospective application is permitted. PacifiCorp is currently evaluating the impact of adopting this guidance on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

(3) Property, Plant and Equipment, Net

Property, plant and equipment, net consists of the following as of December 31 (in millions):

	Depreciable Life	2024	2023
Utility Plant:			
Generation	15 - 59 years	\$ 14,316	\$ 13,904
Transmission	60 - 90 years	10,939	8,216
Distribution	20 - 75 years	9,842	9,060
Intangible plant and other	2 - 75 years	2,958	2,833
Utility plant in-service		38,055	34,013
Accumulated depreciation and amortization		(12,504)	(11,725)
Utility plant in-service, net		25,551	22,288
Nonregulated, net of accumulated depreciation and amortization	14 - 75 years	19	18
		25,570	22,306
Construction work-in-progress		3,550	4,745
Property, plant and equipment, net		\$ 29,120	\$ 27,051

The average depreciation and amortization rate applied to depreciable property, plant and equipment was 3.2%, 3.4% and 3.5% for the years ended December 31, 2024, 2023 and 2022, respectively.

Unallocated Acquisition Adjustments

PacifiCorp has unallocated acquisition adjustments that represent the excess of costs of the acquired interests in property, plant and equipment purchased from the entity that first dedicated the assets to utility service over their net book value in those assets. These unallocated acquisition adjustments included in other property, plant and equipment had an original cost of \$156 million as of December 31, 2024 and 2023, and accumulated depreciation of \$145 million as of December 31, 2024 and 2023.

Government Grants

In November 2024, PacifiCorp accepted two cost share grants from the U.S. Department of Energy ("DOE") under the DOE's Grid Resilience and Innovation Partnerships ("GRIP") Program supported by the Infrastructure Investment and Jobs Act. The two GRIP grants will provide cash proceeds totaling approximately \$150 million as cost reimbursements supporting PacifiCorp's investment in certain wildfire mitigation projects, such as system hardening for fire resistance and prevention and new substation infrastructure, and other investments in technologies that significantly enhance situational awareness to reduce or mitigate wildfires and improve electric grid flexibility, reliability and resiliency. The period of performance for both GRIP grants begins September 2024 and runs through September 2028 and 2029. No costs incurred after the period of performance will be eligible for reimbursement.

In conjunction with the two GRIP awards, the DOE and U.S. Department of Labor accepted PacifiCorp's request for a temporary exception regarding the Davis-Bacon Act weekly pay and certified payroll reporting requirements with which PacifiCorp is required to comply under the terms of the grants. The parties agreed to a curative plan that provides for a temporary means to achieve the goals of these requirements and allows PacifiCorp to have until April 1, 2026, to fully comply with these requirements.

Other current DOE cost share grants primarily support electric vehicle infrastructure programs and energy efficiency programs. The period of performance for the electric vehicle infrastructure grant ended December 2024, and was for total cash proceeds of \$6 million. The period of performance for the energy efficiency grant ends May 2028, and is for total cash proceeds of \$5 million.

On January 20, 2025, U.S. federal executive order entitled *Unleashing American Energy* was issued requiring federal agencies to immediately pause disbursement of federal funds appropriated under the Inflation Reduction Act of 2022 and the Infrastructure Investment and Jobs Act, subject to respective agency review within 90 days of the date of the order of the agency's processes, policies and programs for issuing grants consistent with the policies stated in the executive order. PacifiCorp is monitoring federal activities associated with the executive order to determine whether the funding associated with its grants will be impacted.

Various compliance requirements are associated with the DOE grants, including demonstration that the costs are allowable under the grants. In the event PacifiCorp fails to meet these requirements, it could be required to return funds to the DOE.

During the year ended December 31, 2024, approximately \$11 million of federal grant funds reduced additions to Property, plant and equipment – net on the Consolidated Balance Sheets and approximately \$4 million of federal grant funds reduced operating expenses on the Consolidated Statements of Operations. Federal grant funds received prior to 2024 were insignificant.

(4) Jointly Owned Utility Facilities

Under joint facility ownership agreements with other utilities, PacifiCorp, as a tenant in common, has undivided interests in jointly owned generation, transmission and distribution facilities. PacifiCorp accounts for its proportionate share of each facility, and each joint owner has provided financing for its share of each facility. Operating costs of each facility are assigned to joint owners based on their percentage of ownership or energy production, depending on the nature of the cost. Operating costs and expenses on the Consolidated Statements of Operations include PacifiCorp's share of the expenses of these facilities.

The amounts shown in the table below represent PacifiCorp's share in each jointly owned facility included in property, plant and equipment, net as of December 31, 2024 (dollars in millions):

	PacifiCorp Share	Facility in Service	Accumulated Depreciation and Amortization	Construction Work-in- Progress
Jim Bridger Nos. 1-4	67 %	\$ 1,564	\$ 991	\$ 4
Hunter No. 1	94	509	256	3
Hunter No. 2	60	315	161	1
Wyodak	80	492	301	—
Colstrip Nos. 3 and 4	10	263	217	2
Hermiston	50	191	115	6
Craig Nos. 1 and 2	19	373	352	—
Hayden No. 1	25	77	58	—
Hayden No. 2	13	45	34	—
Transmission and distribution facilities	Various	932	296	308
Total		<u>\$ 4,761</u>	<u>\$ 2,781</u>	<u>\$ 324</u>

(5) Leases

The following table summarizes PacifiCorp's leases recorded on the Consolidated Balance Sheets as of December 31 (in millions):

	<u>2024</u>	<u>2023</u>
Right-of-use assets:		
Operating leases	\$ 11	\$ 12
Finance leases	22	10
Total right-of-use assets	<u>\$ 33</u>	<u>\$ 22</u>
Lease liabilities:		
Operating leases	\$ 11	\$ 12
Finance leases	24	12
Total lease liabilities	<u>\$ 35</u>	<u>\$ 24</u>

The following table summarizes PacifiCorp's lease costs for the years ended December 31 (in millions):

	<u>2024</u>	<u>2023</u>	<u>2022</u>
Variable	\$ 35	\$ 57	\$ 61
Operating	4	4	3
Finance:			
Amortization	1	1	1
Interest	2	1	1
Short-term	6	6	5
Total lease costs	<u>\$ 48</u>	<u>\$ 69</u>	<u>\$ 71</u>
Weighted-average remaining lease term (years):			
Operating leases	12.0	12.3	11.4
Finance leases	7.3	8.8	9.7
Weighted-average discount rate:			
Operating leases	3.8 %	3.8 %	3.9 %
Finance leases	7.8 %	10.6 %	11.4 %

Cash payments associated with operating and finance lease liabilities approximated lease cost for the years ended December 31, 2024, 2023 and 2022.

PacifiCorp has the following remaining lease commitments as of December 31, 2024 (in millions):

	Operating	Finance	Total
2025	\$ 2	\$ 5	\$ 7
2026	2	5	7
2027	2	4	6
2028	1	4	5
2029	1	4	5
Thereafter	7	10	17
Total undiscounted lease payments	15	32	47
Less - amounts representing interest	(4)	(8)	(12)
Lease liabilities	<u>\$ 11</u>	<u>\$ 24</u>	<u>\$ 35</u>

(6) Regulatory Matters

Regulatory Assets

Regulatory assets represent costs that are expected to be recovered in future rates. PacifiCorp's regulatory assets reflected on the Consolidated Balance Sheets consist of the following as of December 31 (in millions):

	Weighted Average Remaining Life	2024	2023
Employee benefit plans ⁽¹⁾	15 years	\$ 265	\$ 279
Utah mine disposition ⁽²⁾	Various	83	79
Deferred net power costs	1 year	1,290	1,117
Unrealized loss on regulated derivative contracts	1 year	97	76
Environmental costs	29 years	145	139
Asset retirement obligation	29 years	393	300
Demand side management (DSM)	10 years	265	245
Wildfire mitigation and vegetation management costs	Various	104	114
Other	Various	275	224
Total regulatory assets		<u>\$ 2,917</u>	<u>\$ 2,573</u>
Reflected as:			
Current assets		\$ 891	\$ 631
Noncurrent assets		2,026	1,942
Total regulatory assets		<u>\$ 2,917</u>	<u>\$ 2,573</u>

(1) Represents amounts not yet recognized as a component of net periodic benefit cost that are expected to be included in rates when recognized.

(2) Amounts represent regulatory assets established as a result of the Utah mine disposition in 2015 for the United Mine Workers of America ("UMWA") 1974 Pension Plan withdrawal and closure costs incurred to date considered probable of recovery. Refer to Note 10 for additional information.

Regulatory assets totaling approximately \$800 million, primarily related to those for Employee benefit plans, Unrealized loss on derivative contracts and Asset retirement obligation, were not accruing interest or included in rate base earning a return on investment as of December 31, 2024. Most other regulatory assets accrue interest but are not included in rate base earning a return on investment. In general, regulatory assets associated with property, plant and equipment are included in rate base and earn a return on investment.

Regulatory Liabilities

Regulatory liabilities represent income to be recognized or amounts to be returned to customers in future periods. PacifiCorp's regulatory liabilities reflected on the Consolidated Balance Sheets consist of the following as of December 31 (in millions):

	Weighted Average Remaining Life	2024	2023
Cost of removal ⁽¹⁾	26 years	\$ 1,560	\$ 1,456
Deferred income taxes ⁽²⁾	Various	861	1,006
Other	Various	221	148
Total regulatory liabilities		<u>\$ 2,642</u>	<u>\$ 2,610</u>
Reflected as:			
Current liabilities		\$ 92	\$ 70
Noncurrent liabilities		2,550	2,540
Total regulatory liabilities		<u>\$ 2,642</u>	<u>\$ 2,610</u>

- (1) Amounts represent estimated costs, as generally accrued through depreciation rates, of removing property, plant and equipment in accordance with accepted regulatory practices. Amounts are deducted from rate base or otherwise accrue a carrying cost.
- (2) Amounts primarily represent income tax liabilities related to the federal tax rate change from 35% to 21% that are probable of being passed on to customers, partially offset by income tax benefits related to certain property-related basis differences and other various differences that were previously passed on to customers and will be included in regulated rates when the temporary differences reverse.

(7) Short-term Debt and Credit Facilities

PacifiCorp has a \$2.0 billion unsecured credit facility expiring in June 2027 with an unlimited number of maturity extension options, subject to lender consent. The credit facility, which supports PacifiCorp's commercial paper program and certain series of its tax-exempt bond obligations and provides for the issuance of a certain level of letters of credit, has a variable interest rate based on the Secured Overnight Financing Rate ("SOFR") or a base rate, at PacifiCorp's option, plus a spread that varies based on PacifiCorp's credit ratings for its senior unsecured long-term debt securities. In addition, PacifiCorp has a \$900 million 364-day unsecured credit facility expiring in June 2025 which, similar to its other existing \$2.0 billion credit facility provides for loans at variable interest rates based on the SOFR or a base rate, at PacifiCorp's option, plus a spread that varies based on PacifiCorp's credit ratings for its senior unsecured long-term debt securities.

The following table summarizes PacifiCorp's availability under its unsecured credit facility as of December 31 (in millions):

2024:

Credit facilities	\$ 2,900
Less:	
Short-term debt	(240)
Tax-exempt bond support	(52)
Net credit facilities	<u>\$ 2,608</u>

2023:

Credit facility	\$ 2,000
Less:	
Short-term debt	(1,604)
Tax-exempt bond support and letters of credit	(249)
Net credit facility	<u>\$ 147</u>

As of December 31, 2024, PacifiCorp was in compliance with all financial covenants that affect access to capital.

As of December 31, 2024 and 2023, PacifiCorp had \$240 million and \$1.6 billion of short-term debt outstanding at a weighted average rate of 4.65% and 6.16%, respectively.

The credit facilities require that PacifiCorp's ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.65 to 1.0 as of the last day of each quarter. As of December 31, 2024, PacifiCorp's debt to total capitalization ratio was 0.57 to 1.0.

As of December 31, 2024, PacifiCorp had \$255 million of letter of credit capacity under its \$2.0 billion revolving credit facility of which no amount was outstanding, and \$488 million of letter of credit capacity outside of its \$2.0 billion revolving credit facility, of which \$34 million was outstanding and was utilized in support of certain transactions required by third parties. Subsequently, PacifiCorp added \$225 million of letter of credit capacity outside of its \$2.0 billion revolving credit facility. As of February 21, 2025, PacifiCorp's total letter of credit capacity outside of its \$2.0 billion revolving credit facility was \$713 million.

As of December 31, 2023, PacifiCorp had \$255 million of letter of credit capacity under the \$2.0 billion revolving credit facility of which \$31 million was outstanding and was utilized as a standby letter of credit, and \$168 million of letter of credit capacity outside of its \$2.0 billion revolving credit facility, of which \$55 million was outstanding and was utilized in support of certain transactions required by third parties.

(8) Long-term Debt

PacifiCorp's long-term debt was as follows as of December 31 (dollars in millions):

	Par Value	2024	2023
First mortgage bonds:			
3.60%, due 2024	\$ —	\$ —	\$ 425
3.35%, due 2025	250	250	250
6.71%, due 2026	100	100	99
5.10%, due 2029	500	498	—
3.50%, due 2029	400	399	399
2.70%, due 2030	400	398	398
5.30%, due 2031	700	696	—
7.70%, due 2031	300	299	299
5.45%, due 2034	1,100	1,093	—
5.90%, due 2034	200	199	199
5.25%, due 2035	300	299	299
6.10%, due 2036	350	348	348
5.75%, due 2037	600	600	600
6.25%, due 2037	600	598	597
6.35%, due 2038	300	298	298
6.00%, due 2039	650	644	644
4.10%, due 2042	300	298	298
4.125%, due 2049	600	594	594
4.15%, due 2050	600	594	593
3.30%, due 2051	600	591	591
2.90%, due 2052	1,000	985	985
5.35%, due 2053	1,100	1,088	1,087
5.50%, due 2054	1,200	1,189	1,189
5.80%, due 2055	1,500	1,478	—
Variable-rate series, tax-exempt bond obligations (2024 - 3.20% to 4.45%; 2023 - 4.60% to 5.60%):			
Secured ⁽¹⁾ , due 2024	—	—	166
Secured ⁽¹⁾ , due 2025	27	27	27
Unsecured, due 2025	25	25	25
Total long-term debt	<u>\$ 13,702</u>	<u>\$ 13,588</u>	<u>\$ 10,410</u>
Reflected as:			
Current portion of long-term debt		\$ 302	\$ 591
Long-term debt		13,286	9,819
Total long-term debt		<u>\$ 13,588</u>	<u>\$ 10,410</u>

(1) Secured by pledged first mortgage bonds registered to and held by the tax-exempt bond trustee generally with the same interest rates, maturity dates and redemption provisions as the tax-exempt bond obligations.

In June 2024, PacifiCorp terminated its \$900 million unsecured delayed draw term loan facility expiring in June 2025 and entered into a new \$900 million 364-day unsecured credit facility expiring in June 2025. Refer to Note 7 for further discussion regarding PacifiCorp's credit facilities.

PacifiCorp's long-term debt generally includes provisions that allow PacifiCorp to redeem the first mortgage bonds in whole or in part at any time through the payment of a make-whole premium. Variable-rate tax-exempt bond obligations are generally redeemable at par value.

PacifiCorp currently has regulatory authority from the Oregon Public Utility Commission and the Idaho Public Utilities Commission to issue an additional \$5.0 billion of long-term debt. PacifiCorp must make a notice filing with the Washington Utilities and Transportation Commission prior to any future issuance. PacifiCorp currently has an effective shelf registration statement filed with the U.S. Securities and Exchange Commission to issue an indeterminate amount of first mortgage bonds and unsecured debt securities through July 2027.

The issuance of PacifiCorp's first mortgage bonds is limited by available property, earnings tests and other provisions of PacifiCorp's mortgage. Approximately \$39.0 billion of PacifiCorp's eligible property (based on original cost) was subject to the lien of the mortgage as of December 31, 2024.

As of December 31, 2024, the annual principal maturities of long-term debt for 2025 and thereafter are as follows (in millions):

2025	\$	302
2026		100
2027		—
2028		—
2029		900
Thereafter		12,400
Total		13,702
Unamortized discount and debt issuance costs		(114)
Total	\$	<u>13,588</u>

(9) Income Taxes

Income tax expense (benefit) consists of the following for the years ended December 31 (in millions):

	2024	2023	2022
Current:			
Federal	\$ (234)	\$ (324)	\$ (216)
State	7	(5)	(3)
Total	<u>(227)</u>	<u>(329)</u>	<u>(219)</u>
Deferred:			
Federal	(9)	(172)	90
State	1	(51)	71
Total	<u>(8)</u>	<u>(223)</u>	<u>161</u>
Investment tax credits	(1)	(1)	(4)
Total income tax expense (benefit)	<u>\$ (236)</u>	<u>\$ (553)</u>	<u>\$ (62)</u>

The effective tax rate for the year ended December 31, 2023, was 54% and results from a \$553 million income tax benefit associated with a \$1,021 million pre-tax loss primarily related to a \$1,677 million increase in wildfire loss accruals, net of expected insurance recoveries as described in Note 14. The \$553 million income tax benefit was primarily comprised of a \$214 million benefit, or 21%, from the application of the federal statutory income tax rate to the pre-tax loss, a \$180 million benefit, or 18%, from federal income tax credits, a \$111 million benefit, or 11%, from effects of ratemaking and a \$41 million benefit, or 4%, from state income tax.

A reconciliation of the federal statutory income tax rate to the effective income tax rate applicable to income (loss) before income tax expense (benefit) is as follows for the years ended December 31:

	2024	2023	2022
Federal statutory income tax rate	21 %	21 %	21 %
State income taxes, net of federal income tax benefit	6	4	3
Effects of ratemaking ⁽¹⁾	(34)	11	(12)
Federal income tax credits	(66)	18	(22)
Valuation allowance	(5)	1	2
Other	—	(1)	1
Effective income tax rate	(78)%	54 %	(7)%

(1) Effects of ratemaking is primarily attributable to activity associated with excess deferred income taxes.

Income tax credits relate primarily to production tax credits ("PTC") earned by PacifiCorp's wind-powered generating facilities. Federal renewable electricity PTCs are earned as energy from qualifying wind-powered generating facilities is produced and sold and are based on a per-kilowatt hour rate pursuant to the applicable federal income tax law. Wind-powered generating facilities are eligible for the credits for 10 years from the date the qualifying generating facilities are placed in-service. PTCs for the years ended December 31, 2024, 2023 and 2022 totaled \$200 million, \$180 million and \$185 million, respectively.

The net deferred income tax liability consists of the following as of December 31 (in millions):

	2024	2023
Deferred income tax assets:		
Regulatory liabilities	\$ 651	\$ 643
Employee benefits	49	51
State carryforwards	88	84
Loss contingencies	380	429
AROs	102	85
Other	125	117
Total deferred income tax assets	1,395	1,409
Valuation allowances	(11)	(24)
Total deferred income tax assets, net	1,384	1,385
Deferred income tax liabilities:		
Property-related items	(3,813)	(3,704)
Regulatory assets	(717)	(632)
Other	(76)	(134)
Total deferred income tax liabilities	(4,606)	(4,470)
Net deferred income tax liability	\$ (3,222)	\$ (3,085)

The following table provides, without regard to valuation allowances, PacifiCorp's net operating loss and tax credit carryforwards and expiration dates as of December 31, 2024 (in millions):

	State
Net operating loss carryforwards	\$ 1,656
Deferred income taxes on net operating loss carryforwards	\$ 73
Expiration dates	2026 - indefinite
Tax credit carryforwards	\$ 15
Expiration dates	2025 - indefinite

The U.S. Internal Revenue Service has closed or effectively settled its examination of PacifiCorp's income tax returns through December 31, 2013. The statute of limitations for PacifiCorp's income tax returns have expired for certain states through December 31, 2011, and for Idaho through December 31, 2020, except for the impact of any federal audit adjustments. The closure of examinations, or the expiration of the statute of limitations, for state filings may not preclude the state from adjusting the state net operating loss carryforward utilized in a year for which the statute of limitations is not closed.

(10) Employee Benefit Plans

PacifiCorp sponsors defined benefit pension and other postretirement benefit plans that cover certain of its employees, as well as a defined contribution 401(k) employee savings plan ("401(k) Plan"). In addition, PacifiCorp contributes to a joint trustee pension plan and a subsidiary previously contributed to a multiemployer pension plan for benefits offered to certain bargaining units.

Defined Benefit Plans

PacifiCorp's pension plans include non-contributory defined benefit pension plans, the PacifiCorp Retirement Plan ("Retirement Plan"), and the Supplemental Executive Retirement Plan ("SERP"). The Retirement Plan is closed to all non-union employees hired after January 1, 2008. All non-union Retirement Plan participants hired prior to January 1, 2008 that did not elect to receive equivalent fixed contributions to the 401(k) Plan effective January 1, 2009 earned benefits based on a cash balance formula through December 31, 2016. Effective January 1, 2017, non-union employee participants with a cash balance benefit in the Retirement Plan are no longer eligible to receive pay credits in their cash balance formula. In general for union employees, benefits under the Retirement Plan were frozen at various dates from December 31, 2007 through December 31, 2011, as they are now being provided with enhanced 401(k) Plan benefits. However, certain limited union Retirement Plan participants continue to earn benefits under the Retirement Plan based on the employee's years of service and a final average pay formula. The SERP was closed to new participants as of March 21, 2006, and froze future accruals for active participants as of December 31, 2014.

PacifiCorp's other postretirement benefit plan provides healthcare and life insurance benefits to eligible retirees.

Pension Settlement

Pension settlement accounting was triggered in 2022 as a result of the amount of lump sum distributions in the Retirement Plan exceeding the service and interest cost threshold. As a result of the settlement accounting, PacifiCorp recognized settlement losses of \$6 million, net of regulatory deferrals, during the year ended December 31, 2022.

Net Periodic Benefit Cost (Credit)

For purposes of calculating the expected return on plan assets, a market-related value is used. The market-related value of plan assets is calculated by spreading the difference between expected and actual investment returns over a five-year period beginning after the first year in which they occur.

Net periodic benefit (credit) cost for the plans included the following components for the years ended December 31 (in millions):

	Pension			Other Postretirement		
	2024	2023	2022	2024	2023	2022
Service cost	\$ —	\$ —	\$ —	\$ 1	\$ 1	\$ 2
Interest cost	37	39	29	11	11	8
Expected return on plan assets	(47)	(49)	(42)	(14)	(13)	(11)
Settlement ⁽¹⁾	—	—	6	—	—	—
Net amortization	9	12	16	(2)	(2)	1
Net periodic benefit (credit) cost	<u>\$ (1)</u>	<u>\$ 2</u>	<u>\$ 9</u>	<u>\$ (4)</u>	<u>\$ (3)</u>	<u>\$ —</u>

(1) Pension amounts represent settlement losses of \$— million, \$— million and \$24 million, net of deferrals of \$— million, \$— million and \$18 million, during the years ended December 31, 2024, 2023 and 2022.

Funded Status

The following table is a reconciliation of the fair value of plan assets for the years ended December 31 (in millions):

	Pension		Other Postretirement	
	2024	2023	2024	2023
Plan assets at fair value, beginning of year	\$ 764	\$ 758	\$ 271	\$ 264
Employer contributions ⁽¹⁾	4	4	—	—
Participant contributions	—	—	3	4
Actual return on plan assets	31	73	15	25
Benefits paid	(71)	(71)	(22)	(22)
Plan assets at fair value, end of year	<u>\$ 728</u>	<u>\$ 764</u>	<u>\$ 267</u>	<u>\$ 271</u>

(1) Pension amounts represent employer contributions to the SERP.

The following table is a reconciliation of the benefit obligations for the years ended December 31 (in millions):

	Pension		Other Postretirement	
	2024	2023	2024	2023
Benefit obligation, beginning of year	\$ 740	\$ 746	\$ 215	\$ 219
Service cost	—	—	1	1
Interest cost	37	39	11	11
Participant contributions	—	—	3	4
Actuarial (gain) loss	(23)	26	(12)	2
Benefits paid	(71)	(71)	(22)	(22)
Benefit obligation, end of year	<u>\$ 683</u>	<u>\$ 740</u>	<u>\$ 196</u>	<u>\$ 215</u>
Accumulated benefit obligation, end of year	<u>\$ 683</u>	<u>\$ 740</u>		

The funded status of the plans and the amounts recognized on the Consolidated Balance Sheets as of December 31 are as follows (in millions):

	Pension		Other Postretirement	
	2024	2023	2024	2023
Plan assets at fair value, end of year	\$ 728	\$ 764	\$ 267	\$ 271
Less - Benefit obligation, end of year	683	740	196	215
Funded status	<u>\$ 45</u>	<u>\$ 24</u>	<u>\$ 71</u>	<u>\$ 56</u>
Amounts recognized on the Consolidated Balance Sheets:				
Other assets	\$ 83	\$ 65	\$ 71	\$ 56
Accrued employee expenses	(4)	(4)	—	—
Other long-term liabilities	(34)	(37)	—	—
Amounts recognized	<u>\$ 45</u>	<u>\$ 24</u>	<u>\$ 71</u>	<u>\$ 56</u>

The SERP has no plan assets; however, PacifiCorp has a Rabbi trust that holds corporate-owned life insurance and other investments to provide funding for the future cash requirements of the SERP. The cash surrender value of all of the policies included in the Rabbi trust, net of amounts borrowed against the cash surrender value, plus the fair market value of other Rabbi trust investments, was \$76 million and \$68 million as of December 31, 2024 and 2023, respectively. These assets are not included in the plan assets in the above table, but are reflected in noncurrent other assets as of December 31, 2024 and 2023, respectively, on the Consolidated Balance Sheets. The projected and accumulated benefit obligations for the SERP were \$38 million and \$41 million at December 31, 2024 and 2023, respectively.

As of December 31, 2024, the fair value of the plan assets for the Retirement Plan was in excess of both the projected benefit obligation and the accumulated benefit obligation.

Unrecognized Amounts

The portion of the funded status of the plans not yet recognized in net periodic benefit cost as of December 31 is as follows (in millions):

	Pension		Other Postretirement	
	2024	2023	2024	2023
Net loss (gain)	\$ 258	\$ 270	\$ (53)	\$ (42)
Regulatory deferrals ⁽¹⁾	19	22	—	—
Total	\$ 277	\$ 292	\$ (53)	\$ (42)

(1) Pension amounts represent the unamortized portion of deferred settlement losses.

A reconciliation of the amounts not yet recognized as components of net periodic benefit cost for the years ended December 31, 2024 and 2023 is as follows (in millions):

	Regulatory Asset	Accumulated Other Comprehensive Loss	Total
<u>Pension</u>			
Balance, December 31, 2022	\$ 290	\$ 12	\$ 302
Net loss arising during the year	—	2	2
Net amortization	(11)	(1)	(12)
Total	(11)	1	(10)
Balance, December 31, 2023	279	13	292
Net gain arising during the year	(5)	(1)	(6)
Net amortization	(9)	—	(9)
Total	(14)	(1)	(15)
Balance, December 31, 2024	<u>\$ 265</u>	<u>\$ 12</u>	<u>\$ 277</u>
			Regulatory Liability
<u>Other Postretirement</u>			
Balance, December 31, 2022			\$ (35)
Net gain arising during the year			(9)
Net amortization			2
Total			(7)
Balance, December 31, 2023			(42)
Net gain arising during the year			(13)
Net amortization			2
Total			(11)
Balance, December 31, 2024			<u>\$ (53)</u>

Plan Assumptions

Assumptions used to determine benefit obligations and net periodic benefit cost were as follows:

	Pension			Other Postretirement		
	2024	2023	2022	2024	2023	2022
Benefit obligations as of December 31:						
Discount rate	5.80 %	5.20 %	5.55 %	5.75 %	5.20 %	5.50 %
Interest crediting rates for cash balance plan - non-union						
2022	N/A	N/A	0.88 %	N/A	N/A	N/A
2023	N/A	4.73 %	4.73 %	N/A	N/A	N/A
2024	5.98 %	5.98 %	4.73 %	N/A	N/A	N/A
2025	5.03 %	5.98 %	2.60 %	N/A	N/A	N/A
2026	5.03 %	3.10 %	2.60 %	N/A	N/A	N/A
2027 and beyond	3.60 %	3.10 %	2.60 %	N/A	N/A	N/A
Interest crediting rates for cash balance plan - union						
2022	N/A	N/A	1.94 %	N/A	N/A	N/A
2023	N/A	3.55 %	3.55 %	N/A	N/A	N/A
2024	4.47 %	4.47 %	3.55 %	N/A	N/A	N/A
2025	4.04 %	4.47 %	2.40 %	N/A	N/A	N/A
2026	4.04 %	2.70 %	2.40 %	N/A	N/A	N/A
2027 and beyond	3.10 %	2.70 %	2.40 %	N/A	N/A	N/A
Net periodic benefit cost for the years ended December 31:						
Discount rate	5.20 %	5.55 %	2.90 %	5.20 %	5.50 %	2.90 %
Expected return on plan assets	5.90 %	6.00 %	4.70 %	4.87 %	4.78 %	3.44 %

In establishing its assumption as to the expected return on plan assets, PacifiCorp utilizes the asset allocation and return assumptions for each asset class based on historical performance and forward-looking views of the financial markets.

As a result of a plan amendment effective on January 1, 2017, the benefit obligation for the Retirement Plan is no longer affected by future increases in compensation. As a result of a labor settlement reached with UMWA in December 2014, the benefit obligation for the other postretirement plan is no longer affected by healthcare cost trends.

Contributions and Benefit Payments

Employer contributions to the pension and other postretirement benefit plans are expected to be \$4 million and \$— million, respectively, during 2025. Funding to PacifiCorp's Retirement Plan trust is based upon the actuarially determined costs of the plan and the requirements of the Internal Revenue Code, the Employee Retirement Income Security Act of 1974 ("ERISA") and the Pension Protection Act of 2006, as amended ("PPA of 2006"). PacifiCorp considers contributing additional amounts from time to time in order to achieve certain funding levels specified under the PPA of 2006. PacifiCorp evaluates a variety of factors, including funded status, income tax laws and regulatory requirements, in determining contributions to its other postretirement benefit plan.

The expected benefit payments to participants in PacifiCorp's pension and other postretirement benefit plans for 2025 through 2029 and for the five years thereafter are summarized below (in millions):

	Projected Benefit Payments	
	Pension	Other Postretirement
2025	\$ 74	\$ 21
2026	71	21
2027	68	21
2028	64	20
2029	61	19
2030-2034	265	82

Plan Assets

Investment Policy and Asset Allocations

PacifiCorp's investment policy for its pension and other postretirement benefit plans is to balance risk and return through a diversified portfolio of debt securities, equity securities and other alternative investments. Maturities for debt securities are managed to targets consistent with prudent risk tolerances. The plans retain outside investment consultants to advise on plan investments within the parameters outlined by the Berkshire Hathaway Energy Company Investment Committee. The investment portfolio is managed in line with the investment policy with sufficient liquidity to meet near-term benefit payments.

The target allocations (percentage of plan assets) for PacifiCorp's pension and other postretirement benefit plan assets are as follows as of December 31, 2024:

	Pension ⁽¹⁾	Other Postretirement ⁽¹⁾
	%	%
Debt securities ⁽²⁾	50 - 80	78 - 85
Equity securities ⁽²⁾	10 - 50	14 - 20
Other	0 - 10	1 - 2

(1) The trust in which the PacifiCorp Retirement Plan is invested includes a separate account that is used to fund benefits for the other postretirement benefit plan. In addition to this separate account, the assets for the other postretirement benefit plan are held in Voluntary Employees' Beneficiary Association ("VEBA") trusts, each of which has its own investment allocation strategies. Target allocations for the other postretirement benefit plan include the separate account of the Retirement Plan trust and the VEBA trusts.

(2) For purposes of target allocation percentages and consistent with the plans' investment policy, investment funds are allocated based on the underlying investments in debt and equity securities.

Fair Value Measurements

The following table presents the fair value of plan assets, by major category, for PacifiCorp's defined benefit pension plan (in millions):

	Input Levels for Fair Value Measurements			
	Level 1 ⁽¹⁾	Level 2 ⁽¹⁾	Level 3 ⁽¹⁾	Total
As of December 31, 2024:				
Cash equivalents	\$ —	\$ 3	\$ —	\$ 3
Debt securities:				
U.S. government obligations	59	—	—	59
Corporate obligations	—	229	—	229
Municipal obligations	—	13	—	13
Agency, asset and mortgage-backed obligations	—	52	—	52
Equity securities:				
U.S. companies	65	—	—	65
Total assets in the fair value hierarchy	<u>\$ 124</u>	<u>\$ 297</u>	<u>\$ —</u>	<u>\$ 421</u>
Investment funds ⁽²⁾ measured at net asset value				285
Limited partnership interests ⁽³⁾ measured at net asset value				22
Investments at fair value				<u>\$ 728</u>
As of December 31, 2023:				
Cash equivalents	\$ —	\$ 28	\$ —	\$ 28
Debt securities:				
U.S. government obligations	52	—	—	52
Corporate obligations	—	232	—	232
Municipal obligations	—	16	—	16
Agency, asset and mortgage-backed obligations	—	47	—	47
Equity securities:				
U.S. companies	53	—	—	53
Total assets in the fair value hierarchy	<u>\$ 105</u>	<u>\$ 323</u>	<u>\$ —</u>	<u>\$ 428</u>
Investment funds ⁽²⁾ measured at net asset value				310
Limited partnership interests ⁽³⁾ measured at net asset value				26
Investments at fair value				<u>\$ 764</u>

(1) Refer to Note 13 for additional discussion regarding the three levels of the fair value hierarchy.

(2) Investment funds are substantially comprised of mutual funds and collective trust funds. These funds consist of equity and debt securities of approximately 40% and 60%, respectively, for 2024 and 41% and 59%, respectively, for 2023, and are invested in U.S. and international securities of approximately 88% and 12%, respectively, for 2024 and 2023.

(3) Limited partnership interests include several funds that invest primarily in real estate.

The following table presents the fair value of plan assets, by major category, for PacifiCorp's defined benefit other postretirement plan (in millions):

	Input Levels for Fair Value Measurements			
	Level 1 ⁽¹⁾	Level 2 ⁽¹⁾	Level 3 ⁽¹⁾	Total
As of December 31, 2024:				
Cash and cash equivalents	\$ —	\$ 6	\$ —	\$ 6
Debt securities:				
U.S. government obligations	16	—	—	16
Corporate obligations	—	34	—	34
Municipal obligations	—	18	—	18
Agency, asset and mortgage-backed obligations	—	52	—	52
Equity securities:				
U.S. companies	7	—	—	7
Total assets in the fair value hierarchy	<u>\$ 23</u>	<u>\$ 110</u>	<u>\$ —</u>	133
Investment funds ⁽²⁾ measured at net asset value				134
Investments at fair value				<u>\$ 267</u>
As of December 31, 2023:				
Cash and cash equivalents	\$ 4	\$ 3	\$ —	\$ 7
Debt securities:				
U.S. government obligations	9	—	—	9
Corporate obligations	—	45	—	45
Municipal obligations	—	19	—	19
Agency, asset and mortgage-backed obligations	—	50	—	50
Equity securities:				
U.S. companies	8	—	—	8
Total assets in the fair value hierarchy	<u>\$ 21</u>	<u>\$ 117</u>	<u>\$ —</u>	138
Investment funds ⁽²⁾ measured at net asset value				133
Investments at fair value				<u>\$ 271</u>

(1) Refer to Note 13 for additional discussion regarding the three levels of the fair value hierarchy.

(2) Investment funds are substantially comprised of mutual funds and collective trust funds. These funds consist of equity and debt securities of approximately 39% and 61%, respectively, for 2024 and 38% and 62%, respectively, for 2023, and are invested in U.S. and international securities of approximately 90% and 10%, respectively, for 2024 and 89% and 11%, respectively, for 2023.

For level 1 investments, a readily observable quoted market price or net asset value of an identical security in an active market is used to record the fair value. For level 2 investments, the fair value is determined using pricing models based on observable market inputs. Shares of mutual funds not registered under the Securities Act of 1933, private equity limited partnership interests, common and commingled trust funds and investment entities are reported at fair value based on the net asset value per unit, which is used for expedience purposes. A fund's net asset value is based on the fair value of the underlying assets held by the fund less its liabilities.

Multiemployer and Joint Trustee Pension Plans

PacifiCorp contributes to the PacifiCorp/IBEW Local 57 Retirement Trust Fund ("Local 57 Trust Fund") (plan number 001) and its subsidiary, Energy West Mining Company, previously contributed to the UMWA 1974 Pension Plan (plan number 002). Contributions to these pension plans are based on the terms of collective bargaining agreements.

As a result of the Utah Mine Disposition and UMW labor settlement, PacifiCorp's subsidiary, Energy West Mining Company, triggered involuntary withdrawal from the UMW 1974 Pension Plan in June 2015 when the UMW employees ceased performing work for the subsidiary. PacifiCorp recorded its estimate of the withdrawal obligation in December 2014 when withdrawal was considered probable and deferred the portion of the obligation considered probable of recovery to a regulatory asset. PacifiCorp has subsequently revised its estimate due to changes in facts and circumstances for a withdrawal occurring by July 2015. As communicated in a letter received in August 2016, the plan trustees determined a withdrawal liability of \$115 million. Energy West Mining Company began making installment payments in November 2016 and has the option to elect a lump sum payment to settle the withdrawal obligation. In January 2024, the withdrawal liability was recalculated by the plan's actuary to be \$80 million as a result of arbitration efforts regarding the interest rate used to compute the obligation. The ultimate amount paid by Energy West Mining Company to settle the obligation is dependent on a variety of factors, including the results of ongoing efforts with the plan trustees and the recent arbitration activities.

The Local 57 Trust Fund is a joint trustee plan such that the board of trustees is represented by an equal number of trustees from PacifiCorp and the union. The Local 57 Trust Fund was established pursuant to the provisions of the Taft-Hartley Act and although formed with the ability for other employers to participate in the plan, there are no other employers that participate in this plan.

The risk of participating in multiemployer pension plans generally differs from single-employer plans in that assets are pooled such that contributions by one employer may be used to provide benefits to employees of other participating employers and plan assets cannot revert to employers. If an employer ceases participation in the plan, the employer may be obligated to pay a withdrawal liability based on the participants' unfunded, vested benefits in the plan. If participating employers withdraw from a multiemployer plan, the unfunded obligations of the plan may be borne by the remaining participating employers.

The following table presents PacifiCorp's participation in individually significant joint trustee and multiemployer pension plans for the years ended December 31 (dollars in millions):

Plan name	Employer Identification Number	PPA of 2006 zone status or plan funded status percentage for plan years beginning July 1,			Funding improvement plan	Surcharge imposed under PPA of 2006	Contributions			Year contributions to plan exceeded more than 5% of total contributions
		2024	2023	2022			2024	2023	2022	
Local 57 Trust Fund	87-0640888	At least 80%	At least 80%	At least 80%	None	None	\$ 5	\$ 5	\$ 6	2024, 2023, 2022

PacifiCorp's minimum contributions to the Local 57 Trust Fund are based on the amount of wages paid to employees covered by the Local 57 Trust Fund collective bargaining agreements, subject to ERISA minimum funding requirements. The collective bargaining agreements governing the Local 57 Trust Fund expire in 2028.

Defined Contribution Plan

PacifiCorp's 401(k) Plan covers substantially all employees. PacifiCorp's matching contributions are based on each participant's level of contribution and, as of January 1, 2024, all participants receive contributions based on eligible pre-tax annual compensation. Contributions cannot exceed the maximum allowable for tax purposes. PacifiCorp's contributions to the 401(k) Plan were \$55 million, \$48 million and \$44 million for the years ended December 31, 2024, 2023 and 2022, respectively.

(11) Asset Retirement Obligations

PacifiCorp estimates its ARO liabilities based upon detailed engineering calculations of the amount and timing of the future cash spending for a third party to perform the required work. Spending estimates are escalated for inflation and then discounted at a credit-adjusted, risk-free rate. Changes in estimates could occur for a number of reasons, including changes in laws and regulations, plan revisions, inflation and changes in the amount and timing of the expected work.

PacifiCorp does not recognize liabilities for AROs for which the fair value cannot be reasonably estimated. Due to the indeterminate removal date, the fair value of the associated liabilities on certain transmission, distribution and other assets cannot currently be estimated, and no amounts are recognized on the Consolidated Financial Statements other than those included in the cost of removal regulatory liability established via approved depreciation rates in accordance with accepted regulatory practices.

The following table reconciles the beginning and ending balances of PacifiCorp's ARO liabilities for the years ended December 31 (in millions):

	2024	2023
Beginning balance	\$ 356	\$ 331
Change in estimated costs	73	(4)
Additions	4	27
Retirements	(20)	(9)
Accretion	14	11
Ending balance	<u>\$ 427</u>	<u>\$ 356</u>
Reflected as:		
Other current liabilities	\$ 49	\$ 9
Other long-term liabilities	378	347
	<u>\$ 427</u>	<u>\$ 356</u>

Certain of PacifiCorp's decommissioning and reclamation obligations relate to jointly owned facilities and mine sites. PacifiCorp is committed to pay a proportionate share of the decommissioning or reclamation costs. In the event of a default by any of the other joint participants, PacifiCorp may be obligated to absorb, directly or by paying additional sums to the entity, a proportionate share of the defaulting party's liability. PacifiCorp's estimated share of the decommissioning and reclamation obligations are primarily recorded as ARO liabilities.

In May 2024, the United States Environmental Protection Agency published its final rule on legacy coal combustion residuals ("CCR") surface impoundments and CCR management units ("CCRMUs") in the Federal Register. CCRMUs include CCR surface impoundments and landfills closed before October 19, 2015 and inactive CCR landfills. The final rule contains three main components: (1) a definition for legacy CCR surface impoundments, which are inactive surface impoundments at inactive generating facilities that must adhere to the same regulations as inactive CCR impoundments at active generating facilities, barring location restrictions and liner design criteria, with customized compliance deadlines; (2) groundwater monitoring, corrective action, closure, and post closure care requirements for CCRMUs, which may be located at active generating facilities and inactive generating facilities with a legacy CCR surface impoundment; and (3) the owners and operators of inactive generating facilities must identify the presence of legacy CCR surface impoundments and comply with all rule requirements for surface impoundments; and the owners and operators of active generating facilities and inactive generating facilities with a legacy CCR surface impoundment must prepare Facility Evaluation Reports ("FERs") that identify and describe the CCRMUs and determine whether closure is required. In a manner consistent with existing CCR rules, owners and operators must publish FERs on their CCR websites in two parts, within 15 months (Part 1) and 27 months (Part 2) of the final rule's effective date in November 2024. PacifiCorp is currently evaluating the final rule and does not anticipate identifying any legacy surface impoundments, but does anticipate identifying CCRMUs subject to the rule. Due to the number of site investigations warranted by this rule and the nature of engineering and other studies required at each site, PacifiCorp is unable to reasonably estimate the potential impact, which may be material, to its asset retirement obligations.

(12) Risk Management and Hedging Activities

PacifiCorp is exposed to the impact of market fluctuations in commodity prices and interest rates. PacifiCorp is principally exposed to electricity, natural gas, coal and fuel oil commodity price risk as it has an obligation to serve retail customer load in its service territories. PacifiCorp's load and generating facilities represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel required to generate electricity and wholesale electricity that is purchased and sold. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather, market liquidity, generating facility availability, customer usage, storage, and transmission and transportation constraints. Interest rate risk exists on variable-rate debt and future debt issuances. PacifiCorp does not engage in a material amount of proprietary trading activities.

PacifiCorp has established a risk management process that is designed to identify, assess, manage and report on each of the various types of risk involved in its business. To mitigate a portion of its commodity price risk, PacifiCorp uses commodity derivative contracts, which may include forwards, futures, options, swaps and other agreements, to effectively secure future supply or sell future production generally at fixed prices. PacifiCorp manages its interest rate risk by limiting its exposure to variable interest rates primarily through the issuance of fixed-rate long-term debt and by monitoring market changes in interest rates. Additionally, PacifiCorp has the ability to enter into interest rate derivative contracts, such as interest rate swaps or locks, to mitigate PacifiCorp's exposure to interest rate risk. No interest rate derivatives were in place during the periods presented. PacifiCorp does not hedge all of its commodity price and interest rate risks, thereby exposing the unhedged portion to changes in market prices.

There have been no significant changes in PacifiCorp's accounting policies related to derivatives. Refer to Notes 2 and 13 for additional information on derivative contracts.

The following table, which reflects master netting arrangements and excludes contracts that have been designated as normal under the normal purchases or normal sales exception afforded by GAAP, summarizes the fair value of PacifiCorp's derivative contracts, on a gross basis, and reconciles those amounts to the amounts presented on a net basis on the Consolidated Balance Sheets (in millions):

	Other Current Assets	Other Assets	Other Current Liabilities	Other Long-term Liabilities	Total
As of December 31, 2024:					
Not designated as hedging contracts⁽¹⁾:					
Commodity assets	\$ 10	\$ —	\$ 16	\$ 1	\$ 27
Commodity liabilities	(1)	—	(105)	(18)	(124)
Total	9	—	(89)	(17)	(97)
Total derivatives	9	—	(89)	(17)	(97)
Cash collateral receivable	—	—	6	—	6
Total derivatives - net basis	<u>\$ 9</u>	<u>\$ —</u>	<u>\$ (83)</u>	<u>\$ (17)</u>	<u>\$ (91)</u>
As of December 31, 2023:					
Not designated as hedging contracts⁽¹⁾:					
Commodity assets	\$ 21	\$ 2	\$ 7	\$ 2	\$ 32
Commodity liabilities	(3)	—	(83)	(22)	(108)
Total	18	2	(76)	(20)	(76)
Total derivatives	18	2	(76)	(20)	(76)
Cash collateral (payable) receivable	(2)	—	12	—	10
Total derivatives - net basis	<u>\$ 16</u>	<u>\$ 2</u>	<u>\$ (64)</u>	<u>\$ (20)</u>	<u>\$ (66)</u>

- (1) PacifiCorp's commodity derivatives are generally included in rates. As of December 31, 2024 a regulatory asset of \$97 million was recorded related to the net derivative liability of \$97 million. As of December 31, 2023 regulatory asset of \$76 million was recorded related to the net derivative liability of \$76 million.

The following table reconciles the beginning and ending balances of PacifiCorp's net regulatory assets (liabilities) and summarizes the pre-tax gains and losses on commodity derivative contracts recognized in net regulatory assets (liabilities), as well as amounts reclassified to earnings for the years ended December 31 (in millions):

	2024	2023	2022
Beginning balance	\$ 76	\$ (270)	\$ (53)
Changes in fair value recognized in regulatory assets (liabilities)	326	206	(513)
Net gains (losses) reclassified to operating revenue	18	(8)	(13)
Net (losses) gains reclassified to cost of fuel and energy	(323)	148	309
Ending balance	<u>\$ 97</u>	<u>\$ 76</u>	<u>\$ (270)</u>

Derivative Contract Volumes

The following table summarizes the net notional amounts of outstanding commodity derivative contracts with fixed price terms that comprise the mark-to-market values as of December 31 (in millions):

	Unit of Measure	2024	2023
Electricity (sales) purchases, net	Megawatt hours	(1)	2
Natural gas purchases	Decatherms	124	153

Credit Risk

PacifiCorp is exposed to counterparty credit risk associated with wholesale energy supply and marketing activities with other utilities, energy marketing companies, financial institutions and other market participants. Credit risk may be concentrated to the extent PacifiCorp's counterparties have similar economic, industry or other characteristics and due to direct or indirect relationships among the counterparties. Before entering into a transaction, PacifiCorp analyzes the financial condition of each significant wholesale counterparty, establishes limits on the amount of unsecured credit to be extended to each counterparty and evaluates the appropriateness of unsecured credit limits on an ongoing basis. To further mitigate wholesale counterparty credit risk, PacifiCorp enters into netting and collateral arrangements that may include margining and cross-product netting agreements and obtains third-party guarantees, letters of credit and cash deposits. If required, PacifiCorp exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

Collateral and Contingent Features

In accordance with industry practice, certain wholesale agreements, including derivative contracts, contain credit support provisions that in part base certain collateral requirements on credit ratings for senior unsecured debt as reported by one or more of the recognized credit rating agencies. These agreements may provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed specified rating-dependent threshold levels ("credit-risk-related contingent features"). These agreements and other agreements that do not refer to specified rating-dependent thresholds may provide the right for counterparties to demand "adequate assurance" if there is a material adverse change in PacifiCorp's creditworthiness. These rights can vary by contract and by counterparty. As of December 31, 2024, PacifiCorp's issuer credit ratings for its senior secured debt and its issuer credit ratings for senior unsecured debt from the recognized credit rating agencies were investment grade.

The aggregate fair value of PacifiCorp's derivative contracts in liability positions with specific credit-risk-related contingent features totaled \$123 million and \$108 million as of December 31, 2024 and 2023, respectively, for which PacifiCorp had posted collateral of \$6 million and \$12 million, respectively, in the form of cash deposits. If all credit-risk-related contingent features for derivative contracts in liability positions had been triggered as of December 31, 2024 and 2023, PacifiCorp would have been required to post \$100 million and \$84 million, respectively, of additional collateral. PacifiCorp's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation or other factors.

(13) Fair Value Measurements

The carrying value of PacifiCorp's cash, certain cash equivalents, receivables, payables, accrued liabilities and short-term borrowings approximates fair value because of the short-term maturity of these instruments. PacifiCorp has various financial assets and liabilities that are measured at fair value on the Consolidated Financial Statements using inputs from the three levels of the fair value hierarchy. A financial asset or liability classification within the hierarchy is determined based on the lowest level input that is significant to the fair value measurement. The three levels are as follows:

- Level 1 - Inputs are unadjusted quoted prices in active markets for identical assets or liabilities that PacifiCorp has the ability to access at the measurement date.
- Level 2 - Inputs include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived principally from or corroborated by observable market data by correlation or other means (market corroborated inputs).
- Level 3 - Unobservable inputs reflect PacifiCorp's judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. PacifiCorp develops these inputs based on the best information available, including its own data.

The following table presents PacifiCorp's financial assets and liabilities recognized on the Consolidated Balance Sheets and measured at fair value on a recurring basis (in millions):

	Input Levels for Fair Value Measurements				
	Level 1	Level 2	Level 3	Other ⁽¹⁾	Total
<u>As of December 31, 2024:</u>					
Assets:					
Commodity derivatives	\$ —	\$ 27	\$ —	\$ (18)	\$ 9
Money market mutual funds	34	—	—	—	34
Investment funds	29	—	—	—	29
	<u>\$ 63</u>	<u>\$ 27</u>	<u>\$ —</u>	<u>\$ (18)</u>	<u>\$ 72</u>
Liabilities - Commodity derivatives	<u>\$ —</u>	<u>\$ (124)</u>	<u>\$ —</u>	<u>\$ 24</u>	<u>\$ (100)</u>
<u>As of December 31, 2023:</u>					
Assets:					
Commodity derivatives	\$ —	\$ 32	\$ —	\$ (14)	\$ 18
Money market mutual funds	175	—	—	—	175
Investment funds	26	—	—	—	26
	<u>\$ 201</u>	<u>\$ 32</u>	<u>\$ —</u>	<u>\$ (14)</u>	<u>\$ 219</u>
Liabilities - Commodity derivatives	<u>\$ —</u>	<u>\$ (108)</u>	<u>\$ —</u>	<u>\$ 24</u>	<u>\$ (84)</u>

- (1) Represents netting under master netting arrangements and a net cash collateral receivable of \$6 million and \$10 million as of December 31, 2024 and 2023, respectively.

Derivative contracts are recorded on the Consolidated Balance Sheets as either assets or liabilities and are stated at estimated fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by GAAP. A discounted cash flow valuation method was used to estimate fair value. When available, the fair value of derivative contracts is estimated using unadjusted quoted prices for identical contracts in the market in which PacifiCorp transacts. When quoted prices for identical contracts are not available, PacifiCorp uses forward price curves. Forward price curves represent PacifiCorp's estimates of the prices at which a buyer or seller could contract today for delivery or settlement at future dates. PacifiCorp bases its forward price curves upon market price quotations, when available, or internally developed and commercial models, with internal and external fundamental data inputs. Market price quotations are obtained from independent energy brokers, exchanges, direct communication with market participants and actual transactions executed by PacifiCorp. Market price quotations for certain major electricity and natural gas trading hubs are generally readily obtainable for the first three years; therefore, PacifiCorp's forward price curves for those locations and periods reflect observable market quotes. Market price quotations for other electricity and natural gas trading hubs are not as readily obtainable for the first three years. Given that limited market data exists for these contracts, as well as for those contracts that are not actively traded, PacifiCorp uses forward price curves derived from internal models based on perceived pricing relationships to major trading hubs that are based on unobservable inputs. The estimated fair value of these derivative contracts is a function of underlying forward commodity prices, interest rates, currency rates, related volatility, counterparty creditworthiness and duration of contracts. Refer to Note 12 for further discussion regarding PacifiCorp's risk management and hedging activities.

PacifiCorp's investments in money market mutual funds and investment funds are stated at fair value. When available, PacifiCorp uses a readily observable quoted market price or net asset value of an identical security in an active market to record the fair value. In the absence of a quoted market price or net asset value of an identical security, the fair value is determined using pricing models or net asset values based on observable market inputs and quoted market prices of securities with similar characteristics.

PacifiCorp's long-term debt is carried at cost on the Consolidated Balance Sheets. The fair value of PacifiCorp's long-term debt is a Level 2 fair value measurement and has been estimated based upon quoted market prices, where available, or at the present value of future cash flows discounted at rates consistent with comparable maturities with similar credit risks. The carrying value of PacifiCorp's variable-rate long-term debt approximates fair value because of the frequent repricing of these instruments at market rates. The following table presents the carrying value and estimated fair value of PacifiCorp's long-term debt as of December 31 (in millions):

	2024		2023	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	\$ 13,588	\$ 12,580	\$ 10,410	\$ 9,722

(14) Commitments and Contingencies

Commitments

PacifiCorp has the following firm commitments that are not reflected on the Consolidated Balance Sheets. Certain commitments are with related parties. Refer to Note 21 for transactions associated with these related party contracts. Minimum payments as of December 31, 2024 are as follows (in millions):

	2025	2026	2027	2028	2029	2030 and Thereafter	Total
Contract type:							
Purchased electricity contracts -							
commercially operable	\$ 358	\$ 195	\$ 194	\$ 197	\$ 196	\$ 1,755	\$ 2,895
Purchased electricity contracts -							
non-commercially operable	34	58	58	58	58	946	1,212
Fuel contracts	825	621	608	489	495	453	3,491
Construction commitments	260	98	9	1	—	—	368
Transmission	108	108	98	93	79	340	826
Easements	15	17	17	17	17	625	708
Maintenance, service and							
other contracts	144	125	89	64	41	110	573
Total commitments	<u>\$ 1,744</u>	<u>\$ 1,222</u>	<u>\$ 1,073</u>	<u>\$ 919</u>	<u>\$ 886</u>	<u>\$ 4,229</u>	<u>\$ 10,073</u>

Purchased Electricity Contracts - Commercially Operable

The table above reflects purchased electricity contracts with expiration dates ranging from 2025 through 2052. As part of its energy resource portfolio, PacifiCorp acquires a portion of its electricity through long-term purchases and exchange agreements. PacifiCorp has many long-term PPAs primarily with solar-powered, wind-powered, or water-powered generating facilities that are not included in the table above due to there being no minimum payments generally due to being dependent on solar, wind and stream flow conditions. These PPAs generally range from 10 to 30 years in duration, with certain of the PPAs extending through 2049. Future payments associated with these PPAs are expected to be material. Certain of these PPAs qualify as leases as described in Note 2. Refer to Note 5 for variable lease costs associated with these lease commitments.

Included in the minimum fixed annual payments for purchased electricity above are commitments to purchase electricity from several hydroelectric systems under long-term arrangements with public utility districts. These purchases are made on a "cost-of-service" basis for a stated percentage of system output and for a like percentage of system operating expenses and debt service. These costs are included in energy costs on the Consolidated Statements of Operations. PacifiCorp is required to pay its portion of operating costs and its portion of the debt service, whether or not any electricity is produced. These arrangements accounted for less than 5% of PacifiCorp's 2024, 2023 and 2022 energy sources.

Purchased Electricity Contracts - Non-Commercially Operable

PacifiCorp has agreements with facilities that have not achieved commercial operation, including PPAs primarily related to wind- and solar-powered generating facilities, as well as battery storage agreements. Certain of these facilities are not included in the table above due to there being no minimum payments generally due to being dependent on wind and solar conditions. The PPAs generally range from 20 to 30 years in duration, with certain of the PPAs extending through 2054. Future payments associated with these arrangements are expected to be material. The table above reflects capacity payments through 2046 for a 400 MW battery storage agreement associated with a purchased electricity contract for a 400 MW solar generating facility. To the extent these facilities do not achieve commercial operation, PacifiCorp has no obligation to the counterparties.

Fuel Contracts

PacifiCorp has "take or pay" coal and natural gas contracts that require minimum payments.

Construction Commitments

PacifiCorp's construction commitments included in the table above relate to firm commitments and include costs associated with certain generating plant, transmission, and distribution projects.

Transmission

PacifiCorp has contracts for the right to transmit electricity over other entities' transmission lines to facilitate delivery to PacifiCorp's customers.

Easements

PacifiCorp has easements for land on which certain of its assets, primarily wind-powered generating facilities, are located.

Environmental Laws and Regulations

PacifiCorp is subject to federal, state and local laws and regulations regarding air quality, climate change, emissions performance standards, water quality, coal ash disposal, wildfire prevention and mitigation and other environmental matters that have the potential to impact its current and future operations. PacifiCorp believes it is in material compliance with all applicable laws and regulations.

Lower Klamath Hydroelectric Project

PacifiCorp is a party to the 2016 amended Klamath Hydroelectric Settlement Agreement ("KHSa"), which addressed disputes surrounding PacifiCorp's efforts to relicense the Klamath Hydroelectric Project. The KHSa established a process for PacifiCorp, the states of Oregon and California ("States") and other stakeholders to assess whether dam removal could occur consistent with the settlement's terms. For PacifiCorp, the key elements of the settlement include: (1) a contribution from PacifiCorp's Oregon and California customers capped at \$200 million plus \$250 million in California bond funds; (2) complete indemnification from harms associated with dam removal; (3) transfer of the Federal Energy Regulatory Commission ("FERC") license to a third-party dam removal entity, the Klamath River Renewal Corporation ("KRRC"); and (4) ability for PacifiCorp to operate the facilities for the benefit of customers through commencement of dam removal.

In September 2016, the KRRC and PacifiCorp filed a joint application with the FERC to transfer the license for the four mainstem Klamath hydroelectric dams comprising the Lower Klamath Project (FERC Project No. 14803) from PacifiCorp to the KRRC. The KRRC filed an amended license surrender application for the Lower Klamath Project with FERC in November 2020. In November 2022, the FERC issued a license surrender order for the Lower Klamath Project, which was accepted by the KRRC and the States in December 2022, resulting in the transfer of the Lower Klamath Project dams. Although PacifiCorp no longer owned the Lower Klamath Project, PacifiCorp continued to operate the facilities under an operation and maintenance agreement with the KRRC until each facility was ready for removal. PacifiCorp's obligations under the operations and maintenance agreement terminated in January 2024, when PacifiCorp's customers no longer received generation benefits from the facilities. Removal of the Copco No. 2 facility was completed in November 2023, and removal of the remaining three dams (J.C. Boyle, Copco No. 1, and Iron Gate) was completed in October 2024. The KRRC has \$450 million in funding available for dam removal and restoration; \$200 million collected from PacifiCorp's Oregon and California customers and \$250 million in California bond funds. PacifiCorp and the States have also agreed to equally share cost overruns that may occur above the initial \$450 million in funding. Specifically, PacifiCorp and the States have agreed to equally fund an initial \$45 million supplemental fund and equally share any additional costs above that amount to ensure dam removal and restoration is complete. In May 2024, the KRRC communicated to PacifiCorp and the States that it expects to require the \$45 million of supplemental funds. In October 2024, PacifiCorp provided approximately \$11 million in supplemental funding to the KRRC.

Hydroelectric Commitments

Certain of PacifiCorp's hydroelectric licenses and settlement agreements contain requirements for PacifiCorp to make certain capital and operating expenditures related to its hydroelectric facilities, which are estimated to be approximately \$333 million over the next 10 years.

Legal Matters

PacifiCorp is party to a variety of legal actions, including litigation, arising out of the normal course of business, some of which assert claims for damages in substantial amounts and are described below. For certain legal actions, parties at times may seek to impose fines, penalties and other costs.

Pursuant to ASC 450, "Contingencies," a provision for a loss contingency is recorded when it is probable a liability is likely to occur, and the amount of loss can be reasonably estimated. PacifiCorp evaluates the related range of reasonably estimated losses and records a loss based on its best estimate within that range or the lower end of the range if there is no better estimate.

Wildfires

As of the date of this filing, a significant number of complaints and demands alleging similar claims related to the Wildfires have been filed in Oregon and California, including a class action complaint in Oregon associated with 2020 Wildfires for which certain jury verdicts were issued as described below. The plaintiffs seek damages for economic losses, noneconomic losses, including mental suffering, emotional distress, personal injury and loss of life, punitive damages, other damages and attorneys' fees. Several insurance carriers have filed subrogation complaints in Oregon and California with allegations similar to those made in the aforementioned complaints. Additionally, PacifiCorp received correspondence from the U.S. and Oregon Departments of Justice regarding the potential recovery of certain costs and damages alleged to have occurred on federal and state lands in connection with certain of the Oregon 2020 Wildfires. In December 2024, the United States of America filed a complaint against PacifiCorp in conjunction with the correspondence from the U.S. Department of Justice. The civil cover sheet accompanying the complaint demands damages estimated to exceed \$900 million. PacifiCorp is actively cooperating with the U.S. and Oregon Departments of Justice on resolving these alleged claims.

Amounts sought in outstanding complaints and demands filed in Oregon and in certain demands made in California totaled approximately \$3 billion, excluding any doubling or trebling of damages included in the complaints and the mass complaints described below that seek \$48 billion. Generally, the complaints filed in California do not specify damages sought and are excluded from this amount. For class actions, amounts specified by the plaintiffs in the complaints include amounts based on estimates of the potential class size, which ultimately may be significantly greater than estimated. Additionally, damages are not limited to the amounts specified in the initially filed complaints as plaintiffs are frequently allowed to amend their complaints to add additional damages and amounts awarded in a court proceeding may be significantly greater than the damages specified. Oregon law provides for doubling of economic and property damages in the event the defendant is found to have acted with gross negligence, recklessness, willfulness or malice. Oregon law provides for trebling of the damages associated with timber, shrubs and produce in the event the defendant is determined to have willfully and intentionally trespassed.

In California, under inverse condemnation, courts have held that investor-owned utilities can be liable for real and personal property damages from wildfires without the utility being found negligent and regardless of fault. California law also permits inverse condemnation plaintiffs to recover reasonable attorney fees and costs. In both Oregon and California, PacifiCorp has equipment in areas accessed through special use permits, easements or similar agreements that may contain provisions requiring it to pay for damages caused by its equipment regardless of fault. Even if inverse condemnation or other provisions do not apply, PacifiCorp could be found liable for all damages.

Based on available information to date, PacifiCorp believes it is probable that losses will be incurred associated with the Wildfires. Final determinations of liability will only be made following the completion of comprehensive investigations, litigation or similar processes, the outcome of which, if adverse, could, in the aggregate, have a material adverse effect on PacifiCorp's financial condition.

2020 Wildfires

In September 2020, a severe weather event resulting in high winds, low humidity and warm temperatures contributed to several major wildfires, which resulted in real and personal property and natural resource damage, personal injuries and loss of life, and widespread power outages in Oregon and Northern California. The wildfires spread across certain parts of PacifiCorp's service territory and surrounding areas across multiple counties in Oregon and California, including Siskiyou County, California; Jackson County, Oregon; Douglas County, Oregon; Marion County, Oregon; Lincoln County, Oregon; and Klamath County, Oregon, burning over 500,000 acres in aggregate. Third-party reports for these wildfires indicate over 2,000 structures destroyed, including residences; several structures damaged; multiple individuals injured; and several fatalities.

Investigations into the cause and origin of each wildfire are complex and ongoing and have been or are being conducted by various entities, including the U.S. Forest Service, the California Public Utilities Commission, the Oregon Department of Forestry, the Oregon Department of Justice, PacifiCorp and various experts engaged by PacifiCorp.

The James Case

On September 30, 2020, a class action complaint against PacifiCorp was filed, captioned *Jeanyne James et al. v. PacifiCorp*, ("*James*") in Oregon Circuit Court in Multnomah County, Oregon ("*Multnomah County Circuit Court Oregon*"). The complaint was filed by Oregon residents and businesses who seek to represent a class of all Oregon citizens and entities whose real or personal property was harmed beginning on September 7, 2020, by wildfires in Oregon allegedly caused by PacifiCorp. In November 2021, the plaintiffs filed an amended complaint to limit the class to include Oregon citizens allegedly impacted by the Santiam Canyon, Echo Mountain Complex, South Obenchain and 242 wildfires. In May 2022, the Multnomah County Circuit Court Oregon granted issue class certification and consolidated the *James* case with several other cases. While PacifiCorp's pre-trial request for immediate appeal of the class certification was denied, it subsequently filed to appeal the class issues as described below.

In April 2023, the jury trial for *James* with respect to 17 named plaintiffs began in Multnomah County Circuit Court Oregon. In June 2023, the jury issued its verdict finding PacifiCorp liable to the 17 named plaintiffs and to the class with respect to the four wildfires. The jury found PacifiCorp's conduct grossly negligent, reckless and willful as to each plaintiff and the entire class. The jury awarded the 17 named plaintiffs \$90 million of damages, including \$4 million of economic damages, \$68 million of noneconomic damages and \$18 million of punitive damages based on a 0.25 multiplier of the economic and noneconomic damages.

In September 2023, the Multnomah County Circuit Court Oregon ordered trial dates for three damages phase trials described below wherein plaintiffs in each of the three damages phase trials would present evidence regarding their damages.

In January 2024, the Multnomah County Circuit Court Oregon entered a limited judgment and money award for the June 2023 *James* verdict. The limited judgment awards \$92 million of damages based on the amounts awarded by the jury, as well as doubling of the economic damages and offsetting of any insurance proceeds received by plaintiffs. The limited judgment created a lien against PacifiCorp, attaching a debt for the money awards. PacifiCorp posted a supersedeas bond, which stays any effort to seek payment of the judgment pending final resolution of any appeals. Under Oregon Revised Statutes 82.010, interest at a rate of 9% per annum will accrue on the judgment commencing at the date the judgment was entered until the entire money award is paid, amended or reversed by an appellate court. In January 2024, PacifiCorp filed a notice of appeal associated with the June 2023 verdict in *James*, including whether the case can proceed as a class action and filed a motion to stay further damages phase trials. On February 14, 2024, the Oregon Court of Appeals denied PacifiCorp's request to stay the damages phase trials. On February 13, 2024, the 17 named plaintiffs filed a notice of cross-appeal as to the January 2024 limited judgment and money award. The appeals process and further actions could take several years.

In January 2024, the jury for the first *James* damages phase trial awarded nine plaintiffs \$62 million of damages, including \$6 million of economic damages and \$56 million of noneconomic damages. After the jury verdict, the Multnomah County Circuit Court Oregon doubled the economic damages to \$12 million and added \$16 million of punitive damages using the 0.25 multiplier determined by the jury for the June 2023 *James* verdict, bringing the total damages awarded to \$84 million. PacifiCorp requested that the Multnomah County Circuit Court Oregon judge offset the damage awards by deducting insurance proceeds received by any of the nine plaintiffs, and on March 25, 2024, the Multnomah County Circuit Court Oregon granted in large part the offset request. In April 2024, the Multnomah County Circuit Court Oregon entered a limited judgment and money award for the January 2024 *James* verdict. The limited judgment awards \$80 million of damages based on the amounts awarded by the jury and offsetting insurance proceeds received by plaintiffs. The limited judgment created a lien against PacifiCorp, attaching a debt for the money awards. In April 2024, PacifiCorp posted a supersedeas bond, which stays any effort to seek payment of the judgment pending final resolution of any appeals. PacifiCorp amended its January 2024 appeal of the June 2023 *James* verdict to include the January 2024 jury verdict.

In March 2024, the jury for the second *James* damages phase trial awarded ten plaintiffs \$42 million of damages, including \$12 million of doubled economic damages, \$23 million of noneconomic damages and \$7 million of punitive damages using the 0.25 multiplier determined by the jury for the June 2023 *James* verdict. PacifiCorp requested that the Multnomah County Circuit Court Oregon judge offset the damage awards by deducting insurance proceeds received by any of the ten plaintiffs and on May 6, 2024, the Multnomah County Circuit Court Oregon granted the offset request. In June 2024, the Multnomah County Circuit Court Oregon entered a limited judgment and money award for the March 2024 *James* verdict. The limited judgment awards \$38 million of damages based on the amounts awarded by the jury and offsetting insurance proceeds received by plaintiffs. The limited judgment created a lien against PacifiCorp, attaching a debt for the money awards. In July 2024, PacifiCorp posted a supersedeas bond, which stays any effort to seek payment of the judgment pending final resolution of any appeals. PacifiCorp further amended its appeal of the June 2023 *James* verdict to include the March 2024 jury verdict.

PacifiCorp's opening brief is due to be filed with the Oregon Court of Appeals on or before February 25, 2025, in connection with its appeal of the June 2023 *James* verdict and the January and March 2024 verdicts for the first two *James damages phase trials*.

In February 2025, the jury for the third *James* damages phase trial awarded seven plaintiffs \$32 million of noneconomic damages in addition to \$4 million of economic damages stipulated for eight plaintiffs prior to the trial. In accordance with Oregon law, plaintiffs asked the court to double the economic damages to \$8 million after the verdict. PacifiCorp expects the court will award the doubling of economic damages and also increase the award for \$9 million in punitive damages by applying the 0.25 multiplier of economic and noneconomic damages consistent with the June 2023 *James* verdict. As a result, PacifiCorp expects the total award for the eight plaintiffs to be approximately \$49 million. PacifiCorp filed post-trial motions with the Multnomah County Circuit Court Oregon requesting the court offset the damage awards by deducting insurance proceeds received by any of the eight plaintiffs. PacifiCorp intends to appeal the jury's damage awards associated with the February 2025 jury verdict once judgment is entered.

In March 2024, settlement was reached with five commercial timber plaintiffs in the *James* consolidated cases, and the jury trial scheduled for April 2024 was cancelled.

In April, May, July and September 2024, and January 2025, six separate mass complaints against PacifiCorp naming 1,591 individual class members were filed in Multnomah County Circuit Court Oregon referencing *James* as the lead case. Complaints for five of the plaintiffs in the mass complaints were subsequently dismissed. These *James* mass complaints make damages-only allegations seeking economic, noneconomic and punitive damages, as well as doubling of economic damages. In December 2024, two additional complaints were filed in Multnomah County Circuit Court Oregon on behalf of eight plaintiffs also referencing *James* as the lead case. PacifiCorp believes the magnitude of damages sought by the class members in the *James* mass complaints and additional two complaints to be of remote likelihood of being awarded based on the amounts awarded in the jury verdicts described above that are being appealed.

In October 2024, the Multnomah County Circuit Court Oregon issued a case management order, which sets forth nine additional damages phase trials with up to 10 plaintiffs per trial. The trials are scheduled to begin February 3, March 24, April 21, May 12, June 2, July 7, September 9, October 6 and December 7, 2025. The verdict for the trial that began February 3, 2025, was issued in February 2025 as described above.

2022 McKinney Fire

According to the California Department of Forestry and Fire Protection, a wildfire began on July 29, 2022, in the Oak Knoll Ranger District of the Klamath National Forest in Siskiyou County, California located in PacifiCorp's service territory, burning over 60,000 acres. Third-party reports indicate that the 2022 McKinney Fire resulted in 11 structures damaged; 185 structures destroyed, including residences; 12 injuries; and four fatalities. The U.S. Forest Service issued a Wildland Fire Origin and Cause Supplemental Incident Report. The report concluded that a tree coming in contact with a power line is the probable cause of the 2022 McKinney Fire.

Estimated Losses for and Settlements Associated with the Wildfires

Based on the facts and circumstances available to PacifiCorp as of the date of this filing, including (i) ongoing cause and origin investigations; (ii) ongoing settlement and mediation discussions; (iii) other litigation matters and upcoming legal proceedings; and (iv) the status of the *James* case, PacifiCorp recorded cumulative estimated probable losses associated with the Wildfires of \$2,753 million through December 31, 2024. PacifiCorp's cumulative accrual includes estimates of probable losses for fire suppression costs, real and personal property damages, natural resource damages and noneconomic damages such as personal injury damages and loss of life damages that it is reasonably able to estimate at this time and which is subject to change as additional relevant information becomes available.

Through December 31, 2024, PacifiCorp paid \$1,217 million in settlements associated with the Wildfires. As a result of the settlements, various trials have been cancelled.

The following table presents changes in PacifiCorp's liability for estimated losses associated with the Wildfires for the years ended December 31 (in millions):

	<u>2024</u>	<u>2023</u>	<u>2022</u>
Beginning balance	\$ 1,723	\$ 424	\$ 252
Accrued losses	346	1,930	225
Payments	(533)	(631)	(53)
Ending balance	<u>\$ 1,536</u>	<u>\$ 1,723</u>	<u>\$ 424</u>

As of December 31, 2024 and 2023, \$247 million and \$4 million of PacifiCorp's liability for estimated losses associated with the Wildfires is classified as a current liability captioned Wildfires liabilities on the Consolidated Balance Sheets. The amounts reflected as current as of December 31, 2024 reflect amounts reasonably expected to be paid out within the next year based on settlements reached as well as ongoing settlement and mediation efforts. The remainder of PacifiCorp's liability for estimated losses associated with the Wildfires as of December 31, 2024 and 2023 is classified as a noncurrent liability captioned Wildfires liabilities on the Consolidated Balance Sheets. In January and February 2025, PacifiCorp made additional settlement payments related to the Wildfires totaling \$114 million.

The following table presents changes in PacifiCorp's receivable for expected insurance recoveries associated with the Wildfires for the years ended December 31 (in millions):

	<u>2024</u>	<u>2023</u>	<u>2022</u>
Beginning balance	\$ 499	\$ 246	\$ 116
Accruals	—	253	161
Payments received	(401)	—	(31)
Ending balance	<u>\$ 98</u>	<u>\$ 499</u>	<u>\$ 246</u>

As of December 31, 2024, PacifiCorp's receivable for expected insurance recoveries was included in Other receivables, net on the Consolidated Balance Sheets. As of December 31, 2023, \$350 million of PacifiCorp's receivable for expected insurance recoveries was included in Other receivables, net while the remaining \$149 million was included in Other assets on the Consolidated Balance Sheets. In January and February 2025, PacifiCorp received insurance proceeds associated with the Wildfires totaling \$28 million.

During the years ended December 31, 2024, 2023 and 2022, PacifiCorp recognized probable losses net of expected insurance recoveries associated with the Wildfires of \$346 million, \$1,677 million and \$64 million, respectively. No additional insurance recoveries beyond those accrued and received to date are expected to be available.

It is reasonably possible PacifiCorp will incur material additional losses beyond the amounts accrued for the Wildfires that could have a material adverse effect on PacifiCorp's financial condition. PacifiCorp is currently unable to reasonably estimate a specific range of possible additional losses that could be incurred due to the number of properties and parties involved, including claimants in the class to the *James* case and the 2022 McKinney Fire, the variation in the types of properties and damages and the ultimate outcome of legal actions, including mediation, settlement negotiations, jury verdicts and the appeals process.

Guarantees

PacifiCorp has entered into guarantees as part of the normal course of business and the sale or transfer of certain assets. These guarantees are not expected to have a material impact on PacifiCorp's consolidated financial results.

(15) Revenue from Contracts with Customers

The following table summarizes PacifiCorp's Customer Revenue by line of business, with further disaggregation of retail by customer class, for the years ended December 31 (in millions):

	2024	2023	2022
Customer Revenue:			
Retail:			
Residential	\$ 2,382	\$ 2,156	\$ 2,013
Commercial	2,096	1,829	1,645
Industrial	1,333	1,179	1,163
Other retail	351	298	278
Total retail	6,162	5,462	5,099
Wholesale	80	165	260
Transmission	176	151	166
Other Customer Revenue	121	129	102
Total Customer Revenue	6,539	5,907	5,627
Other revenue	61	29	52
Total operating revenue	\$ 6,600	\$ 5,936	\$ 5,679

(16) Preferred Stock

As of December 31, 2024 and 2023, PacifiCorp had 3,500 thousand shares of Serial Preferred Stock authorized at the stated value of \$100 per share. PacifiCorp had 24 thousand shares of such Serial Preferred Stock issued and outstanding as of December 31, 2024 and 2023. The outstanding preferred stock series are non-redeemable and have annual dividend rates of 6.00% and 7.00%.

In the event of voluntary liquidation, all preferred stock is entitled to stated value or a specified preference amount per share plus accrued dividends. Upon involuntary liquidation, all preferred stock is entitled to stated value plus accrued dividends. Dividends on all preferred stock are cumulative. Holders also have the right to elect members to the PacifiCorp Board of Directors in the event dividends payable are in default in an amount equal to four full quarterly payments.

As of December 31, 2024, PacifiCorp had 16 million shares of Preferred Stock authorized, but no shares were issued or outstanding. As of December 31, 2023, PacifiCorp had 16 million shares of No Par Preferred Stock and 127 thousand shares of 5% Preferred Stock authorized, but no shares were issued or outstanding.

On December 17, 2024, PPW Holdings LLC, PacifiCorp's direct parent and sole holder of the common stock of PacifiCorp, commenced a tender offer to purchase for cash any and all of PacifiCorp's outstanding 6.00% and 7.00% Serial Preferred Stock (together the "Serial Preferred Stock"). After giving effect to the tender offer, which expired on January 24, 2025, PPW Holdings LLC held 2,494 shares of the 5,930 issued and outstanding shares of the 6.00% Serial Preferred Stock and 10,269 shares of the 18,046 issued and outstanding shares of the 7.00% Serial Preferred Stock.

On February 10, 2025, PacifiCorp effected a one-for-ten thousand reverse stock split ("Reverse Stock Split") of its Serial Preferred Stock.

As a result of the Reverse Stock Split, every 10,000 shares of each of PacifiCorp's pre-reverse split Serial Preferred Stock were combined and reclassified into one share of Serial Preferred Stock, with a corresponding reduction in the number of authorized shares of Serial Preferred Stock from 3,500 thousand to 350 and change to stated value of \$100 to \$1,000,000 per share. No fractional shares were issued in connection with the Reverse Stock Split and shareholders who would have otherwise held a fractional share of Serial Preferred Stock received payment in cash.

As of February 10, 2025, there was one share of 7.00% Serial Preferred Stock outstanding, held by PPW Holdings LLC, and there were no shares of 6.00% Serial Preferred Stock outstanding. As a result, all issued and outstanding shares of PacifiCorp's preferred stock as of February 10, 2025, were held by PPW Holdings LLC.

(17) Common Shareholder's Equity

Through PPW Holdings LLC, BHE is the sole shareholder of PacifiCorp's common stock. The state regulatory orders that authorized BHE's acquisition of PacifiCorp contain restrictions on PacifiCorp's ability to pay dividends to the extent that they would reduce PacifiCorp's common equity below specified percentages of defined capitalization. As of December 31, 2024, the most restrictive of these commitments prohibits PacifiCorp from making any distribution to PPW Holdings LLC or BHE without prior state regulatory approval to the extent that it would reduce PacifiCorp's common equity below 44.00% of its total capitalization, excluding short-term debt and current maturities of long-term debt. As of December 31, 2024, PacifiCorp's actual common equity percentage, as calculated under this measure, was 44.17%. BHE has indicated that it will suspend dividends for the next several years in order to allow PacifiCorp to accumulate cash that may be necessary in the event of additional future settlements associated with the Wildfires.

These commitments also restrict PacifiCorp from making any distributions to either PPW Holdings LLC or BHE if PacifiCorp's senior unsecured debt rating is BBB- or lower by Standard & Poor's Rating Services or Fitch Ratings, or Baa3 or lower by Moody's Investor Service, as indicated by two of the three rating services. As of December 31, 2024, PacifiCorp met these minimum required senior unsecured debt ratings.

PacifiCorp is also subject to a maximum debt-to-total capitalization percentage under various financing agreements as further discussed in Note 7.

(18) Components of Accumulated Other Comprehensive Loss, Net

Accumulated other comprehensive loss, net consists of unrecognized amounts on retirement benefits, net of tax, of \$9 million and \$10 million as of December 31, 2024 and 2023, respectively.

(19) Variable Interest Entities

PacifiCorp holds a 66.67% interest in Bridger Coal Company ("Bridger Coal"), which supplies coal to the Jim Bridger generating facility that is owned 66.67% by PacifiCorp and 33.33% by PacifiCorp's joint venture partner in Bridger Coal. PacifiCorp purchases 66.67% of the coal produced by Bridger Coal, while the joint venture partner purchases the remaining 33.33% of the coal produced. The power to direct the activities that most significantly impact Bridger Coal's economic performance are shared with the joint venture partner. Each joint venture partner is jointly and severally liable for the obligations of Bridger Coal. Bridger Coal's necessary working capital to carry out its mining operations is financed by contributions from PacifiCorp and its joint venture partner. PacifiCorp's equity investment in Bridger Coal was \$42 million and \$48 million as of December 31, 2024 and 2023, respectively. Refer to Note 21 for information regarding related party transactions with Bridger Coal.

(20) Supplemental Cash Flow Disclosures

The summary of supplemental cash flow disclosures as of and for the years ended December 31 is as follows (in millions):

	2024	2023	2022
Supplemental disclosure of cash flow information:			
Interest paid, net of amounts capitalized	\$ 527	\$ 432	\$ 380
Income taxes received, net	\$ 349	\$ 292	\$ 185
Supplemental disclosure of non-cash investing and financing activities:			
Accruals related to property, plant and equipment additions	\$ 773	\$ 862	\$ 558

(21) Related Party Transactions

PacifiCorp has an intercompany administrative services agreement and a mutual assistance agreement with BHE and its subsidiaries. Amounts charged to PacifiCorp by BHE and its subsidiaries under these agreements totaled \$147 million, \$168 million and \$123 million during the years ended December 31, 2024, 2023 and 2022, respectively. Amounts charged to PacifiCorp in 2024 and 2023 were primarily reflected in construction work in progress on the Consolidated Balance Sheets as of December 31, 2024 and 2023. Payables associated with the charges were \$89 million and \$15 million as of December 31, 2024 and 2023, respectively. Amounts charged by PacifiCorp to BHE and its subsidiaries under these agreements totaled \$41 million, \$44 million and \$23 million during the years ended December 31, 2024, 2023 and 2022, respectively. Receivables associated with the charges were \$5 million and \$8 million as of December 31, 2024 and 2023, respectively. Such amounts primarily relate to information technology projects and other costs managed at a consolidated level and allocated or passed through to affiliates.

PacifiCorp also engages in various transactions with several subsidiaries of BHE in the ordinary course of business. Services provided by these subsidiaries in the ordinary course of business and charged to PacifiCorp primarily relate to wholesale electricity purchases and transmission of electricity, transportation of natural gas and employee relocation services. These expenses totaled \$8 million, \$6 million and \$8 million during the years ended December 31, 2024, 2023 and 2022, respectively.

PacifiCorp has long-term transportation contracts with BNSF Railway Company, an indirect wholly owned subsidiary of Berkshire Hathaway, PacifiCorp's ultimate parent company. Transportation costs under these contracts were \$22 million, \$24 million and \$21 million during the years ended December 31, 2024, 2023 and 2022, respectively.

PacifiCorp has a long-term master materials supply contract with Marmon Utility, LLC, an indirect wholly owned subsidiary of a holding company in which Berkshire Hathaway holds a majority interest. Materials and supplies purchased under this contract were \$5 million, \$17 million and \$8 million during the years ended December 31, 2024, 2023 and 2022, respectively.

PacifiCorp is party to a tax-sharing agreement and is part of the Berkshire Hathaway consolidated U.S. federal income tax return. Federal income taxes receivable from BHE were \$3 million and state income taxes payable to BHE were \$11 million as of December 31, 2024. Federal and state income taxes receivable from BHE were \$114 million as of December 31, 2023. For the years ended December 31, 2024, 2023 and 2022, cash refunded from BHE for federal and state income taxes totaled \$349 million, \$292 million and \$185 million, respectively.

PacifiCorp transacts with its equity investees, Bridger Coal and Trapper Mining Inc. Services provided by equity investees to PacifiCorp primarily relate to coal purchases. During the years ended December 31, 2024, 2023 and 2022, coal purchases from PacifiCorp's equity investees totaled \$132 million, \$139 million and \$119 million, respectively. Payables to PacifiCorp's equity investees were \$36 million and \$34 million as of December 31, 2024 and 2023, respectively.

On December 17, 2024, PPW Holdings LLC, an affiliate and sole holder of the common stock of PacifiCorp, commenced a tender offer to purchase for cash any and all of the outstanding 6.00% and 7.00% Serial Preferred Stock. Refer to Note 16 for information regarding the tender offer and subsequent Reverse Stock Split.

Receivables from PPW Holdings LLC for invoices temporarily funded by PacifiCorp on PPW Holdings LLC's behalf were \$20 million as of December 31, 2024.

**MidAmerican Funding, LLC and its subsidiaries and MidAmerican Energy Company
Consolidated Financial Section**

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

The following is management's discussion and analysis of certain significant factors that have affected the consolidated financial condition and results of operations of MidAmerican Funding and its subsidiaries and MidAmerican Energy during the periods included herein. Information in Management's Discussion and Analysis related to MidAmerican Energy, whether or not segregated, also relates to MidAmerican Funding. Information related to other subsidiaries of MidAmerican Funding pertains only to the discussion of the financial condition and results of operations of MidAmerican Funding. Where necessary, discussions have been segregated under the heading "MidAmerican Funding" to allow the reader to identify information applicable only to MidAmerican Funding. Explanations include management's best estimate of the impact of weather, customer growth, usage trends and other factors. This discussion should be read in conjunction with MidAmerican Funding's historical Consolidated Financial Statements and Notes to Consolidated Financial Statements and MidAmerican Energy's historical Financial Statements and Notes to Financial Statements each in Item 8 of this Form 10-K. MidAmerican Funding's and MidAmerican Energy's actual results in the future could differ significantly from the historical results.

Results of Operations

Overview

MidAmerican Energy -

MidAmerican Energy's net income for 2024 was \$1,003 million, an increase of \$21 million, or 2%, compared to 2023 primarily due to a favorable income tax benefit, higher natural gas utility margin, higher interest income, higher AFUDC and favorable changes in the cash surrender value of corporate-owned life insurance policies. These items were partially offset by higher depreciation and amortization expense, higher interest expense, higher operations and maintenance expense, lower electric utility margin and higher property and other taxes. Utility margin increased primarily due to higher natural gas base rates and higher electric retail customer usage, partially offset by lower wholesale margin and the unfavorable impact of weather. Electric retail customer volumes increased 1.2% primarily due to higher customer usage for certain industrial and other customers, partially offset by lower customer usage for certain commercial and residential customers and the unfavorable impact of weather. Wholesale electricity sales volumes decreased 5% due to unfavorable market conditions. Energy generated increased 2% primarily due to 7% higher renewable-powered generation, partially offset by 13% lower coal-fueled generation. Energy purchased volumes decreased 23% primarily due to the increase in energy generated and decreased total sales of 1%. Natural gas retail customer volumes decreased 5% due to the unfavorable impact of weather.

MidAmerican Energy's net income for 2023 was \$982 million, an increase of \$21 million, or 2%, compared to 2022 primarily due to lower depreciation and amortization expense, favorable changes in the cash surrender value of corporate-owned life insurance policies and higher AFUDC. These items were partially offset by lower electric utility margin, an unfavorable income tax benefit, higher interest expense, higher operations and maintenance expense, higher property and other taxes and lower natural gas utility margin. Electric utility margin decreased due to lower wholesale utility margin from lower margin per unit and lower wholesale customer volumes of 15.8%, offset by higher retail utility margin, largely from higher retail customer volumes. Retail customer volumes increased 1.3% primarily due to higher customer usage for certain industrial customers, partially offset by the unfavorable impact of weather. Energy generated decreased 6% primarily due to lower wind-powered generation, partially offset by higher natural gas-fueled generation, and energy purchased increased 4%.

MidAmerican Funding -

MidAmerican Funding's net income for 2024 was \$991 million, an increase of \$11 million, or 1%, compared to 2023. MidAmerican Funding's net income for 2023 was \$980 million, an increase of \$33 million, or 3%, compared to 2022. The increases were primarily due to the changes in MidAmerican Energy's earnings discussed above and a one-time gain on the sale of an investment of \$10 million in 2023.

Non-GAAP Financial Measure

Management utilizes various key financial measures that are prepared in accordance with GAAP, as well as non-GAAP financial measures such as electric utility margin and natural gas utility margin, to help evaluate results of operations. Electric utility margin is calculated as regulated electric operating revenue less cost of fuel and energy, which are captions presented on the Statements of Operations. Natural gas utility margin is calculated as regulated natural gas operating revenue less cost of natural gas purchased for resale, which are included in regulated natural gas and other and cost of natural gas purchased for resale and other, respectively, on the Statements of Operations.

MidAmerican Energy's cost of fuel and energy and cost of natural gas purchased for resale are generally recovered from its retail customers through regulatory recovery mechanisms and, as a result, changes in MidAmerican Energy's expenses included in regulatory recovery mechanisms result in comparable changes to revenue. As such, management believes electric utility margin and natural gas utility margin more appropriately and concisely explain results of operations rather than a discussion of revenue and cost of sales separately. Management believes the presentation of electric utility margin and natural gas utility margin provides meaningful and valuable insight into the information management considers important to understanding the business and a measure of comparability to others in the industry.

Electric utility margin and natural gas utility margin are not measures calculated in accordance with GAAP and should be viewed as a supplement to, and not a substitute for, operating income, which is the most directly comparable financial measure prepared in accordance with GAAP. The following table provides a reconciliation of utility margin to operating income for the years ended December 31 (in millions):

	<u>2024</u>	<u>2023</u>	<u>Change</u>		<u>2023</u>	<u>2022</u>	<u>Change</u>	
Electric utility margin:								
Operating revenue	\$ 2,584	\$ 2,673	\$ (89)	(3)%	\$ 2,673	\$ 2,988	\$ (315)	(11)%
Cost of fuel and energy	<u>430</u>	<u>501</u>	<u>(71)</u>	(14)	<u>501</u>	<u>679</u>	<u>(178)</u>	(26)
Electric utility margin	<u>2,154</u>	<u>2,172</u>	<u>(18)</u>	(1)%	<u>2,172</u>	<u>2,309</u>	<u>(137)</u>	(6)%
Natural gas utility margin:								
Operating revenue	658	713	(55)	(8)%	713	1,030	(317)	(31)%
Cost of natural gas purchased for resale	<u>367</u>	<u>451</u>	<u>(84)</u>	(19)	<u>451</u>	<u>762</u>	<u>(311)</u>	(41)%
Natural gas utility margin	<u>291</u>	<u>262</u>	<u>29</u>	11 %	<u>262</u>	<u>268</u>	<u>(6)</u>	(2)%
Utility margin	\$ 2,445	\$ 2,434	\$ 11	— %	\$ 2,434	\$ 2,577	\$ (143)	(6)%
Other operating revenue	9	7	2	29 %	7	7	—	— %
Other cost of sales	—	—	—	— %	—	1	(1)	(100)
Operations and maintenance	879	851	28	3	851	828	23	3
Depreciation and amortization	1,001	908	93	10	908	1,168	(260)	(22)
Property and other taxes	<u>166</u>	<u>161</u>	<u>5</u>	3	<u>161</u>	<u>149</u>	<u>12</u>	8
Operating income	<u>\$ 408</u>	<u>\$ 521</u>	<u>\$ (113)</u>	(22)%	<u>\$ 521</u>	<u>\$ 438</u>	<u>\$ 83</u>	19 %

Electric Utility Margin

A comparison of key operating results related to electric utility margin is as follows for the years ended December 31:

	2024	2023	Change		2023	2022	Change	
Utility margin (in millions):								
Operating revenue	\$ 2,584	\$ 2,673	\$ (89)	(3)%	\$ 2,673	\$ 2,988	\$ (315)	(11)%
Cost of fuel and energy	430	501	(71)	(14)	501	679	(178)	(26)
Utility margin	<u>\$ 2,154</u>	<u>\$ 2,172</u>	<u>\$ (18)</u>	(1)%	<u>\$ 2,172</u>	<u>\$ 2,309</u>	<u>\$ (137)</u>	(6)%
Sales (GWhs):								
Residential	6,691	6,759	(68)	(1)%	6,759	7,006	(247)	(4)%
Commercial	3,926	3,992	(66)	(2)	3,992	4,017	(25)	(1)
Industrial	17,773	17,307	466	3	17,307	16,646	661	4
Other	1,646	1,617	29	2	1,617	1,621	(4)	—
Total retail	30,036	29,675	361	1	29,675	29,290	385	1
Wholesale	14,329	15,129	(800)	(5)	15,129	17,964	(2,835)	(16)
Total sales	<u>44,365</u>	<u>44,804</u>	<u>(439)</u>	(1)%	<u>44,804</u>	<u>47,254</u>	<u>(2,450)</u>	(5)%
Average number of retail customers (in thousands)								
	829	820	9	1 %	820	813	7	1 %
Average revenue per MWh:								
Retail	\$ 76.13	\$ 77.82	\$ (1.69)	(2)%	\$ 77.82	\$ 79.23	\$ (1.41)	(2)%
Wholesale	\$ 13.44	\$ 17.92	\$ (4.48)	(25)%	\$ 17.92	\$ 31.07	\$ (13.15)	(42)%
Heating degree days								
	5,045	5,371	(326)	(6)%	5,371	6,449	(1,078)	(17)%
Cooling degree days								
	1,188	1,255	(67)	(5)%	1,255	1,274	(19)	(1)%
Sources of energy (GWhs) ⁽¹⁾ :								
Wind, solar and hydroelectric ⁽²⁾	26,691	24,877	1,814	7 %	24,877	28,129	(3,252)	(12)%
Coal	8,637	9,961	(1,324)	(13)	9,961	10,078	(117)	(1)
Nuclear	3,873	3,790	83	2	3,790	3,782	8	—
Natural gas	2,224	2,184	40	2	2,184	1,504	680	45
Total energy generated	41,425	40,812	613	2	40,812	43,493	(2,681)	(6)
Energy purchased	3,676	4,772	(1,096)	(23)	4,772	4,594	178	4
Total	<u>45,101</u>	<u>45,584</u>	<u>(483)</u>	(1)%	<u>45,584</u>	<u>48,087</u>	<u>(2,503)</u>	(5)%
Average cost of energy per MWh:								
Energy generated ⁽³⁾	\$ 5.67	\$ 6.80	\$ (1.13)	(17)%	\$ 6.80	\$ 7.42	\$ (0.62)	(8)%
Energy purchased	\$ 52.86	\$ 46.86	\$ 6.00	13 %	\$ 46.86	\$ 77.59	\$ (30.73)	(40)%

(1) GWh amounts are net of energy used by the related generating facilities.

(2) All or some of the renewable energy attributes associated with generation from these sources may be: (a) used in future years to comply with RPS or other regulatory requirements or (b) sold to third parties in the form of RECs or other environmental commodities.

(3) The average cost per MWh of energy generated includes only the cost of fuel associated with the generating facilities.

Natural Gas Utility Margin

A comparison of key operating results related to natural gas utility margin is as follows for the years ended December 31:

	2024	2023	Change		2023	2022	Change	
Utility margin (in millions):								
Operating revenue	\$ 658	\$ 713	\$ (55)	(8)%	\$ 713	\$ 1,030	\$ (317)	(31)%
Cost of natural gas purchased for resale	367	451	(84)	(19)	451	762	(311)	(41)
Utility margin	<u>\$ 291</u>	<u>\$ 262</u>	<u>\$ 29</u>	11 %	<u>\$ 262</u>	<u>\$ 268</u>	<u>\$ (6)</u>	(2)%
Throughput (000's Dths):								
Residential	44,615	47,558	(2,943)	(6)%	47,558	56,100	(8,542)	(15)%
Commercial	21,648	22,715	(1,067)	(5)	22,715	26,298	(3,583)	(14)
Industrial	5,680	5,799	(119)	(2)	5,799	6,039	(240)	(4)
Other	73	76	(3)	(4)	76	75	1	1
Total retail sales	72,016	76,148	(4,132)	(5)	76,148	88,512	(12,364)	(14)
Wholesale sales	30,170	30,764	(594)	(2)	30,764	30,996	(232)	(1)
Total sales	102,186	106,912	(4,726)	(4)	106,912	119,508	(12,596)	(11)
Natural gas transportation service	108,666	106,422	2,244	2	106,422	102,827	3,595	3
Total throughput	<u>210,852</u>	<u>213,334</u>	<u>(2,482)</u>	(1)%	<u>213,334</u>	<u>222,335</u>	<u>(9,001)</u>	(4)%
Average number of retail customers (in thousands)								
	803	796	7	1 %	796	789	7	1 %
Average revenue per retail Dth sold	\$ 7.70	\$ 7.80	\$ (0.10)	(1)%	\$ 7.80	\$ 9.19	\$ (1.39)	(15)%
Heating degree days	5,292	5,668	(376)	(7)%	5,668	6,810	(1,142)	(17)%
Average cost of natural gas per retail Dth sold								
	\$ 4.59	\$ 4.98	\$ (0.39)	(8)%	\$ 4.98	\$ 6.66	\$ (1.68)	(25)%
Combined retail and wholesale average cost of natural gas per Dth sold								
	\$ 3.60	\$ 4.22	\$ (0.62)	(15)%	\$ 4.22	\$ 6.38	\$ (2.16)	(34)%

Year Ended December 31, 2024 Compared to Year Ended December 31, 2023

MidAmerican Energy -

Electric utility margin decreased \$18 million, or 1%, for 2024 compared to 2023 primarily due to:

- \$33 million decrease in wholesale utility margin due to lower margin per unit of \$19 million, reflecting lower market prices, and lower volumes of \$14 million or 5.3%; partially offset by
- \$16 million increase in retail utility margin primarily due to \$42 million from higher recoveries through bill riders (partially offset in operations and maintenance expense) and \$24 million from higher customer usage, partially offset by \$42 million of lower recoveries through bill riders (offset in income tax benefit) and \$12 million from the unfavorable impact of weather. Retail customer volumes increased 1.2%.

Natural gas utility margin increased \$29 million, or 11%, for 2024 compared to 2023 primarily due to:

- \$32 million increase from higher base rates; and
- \$5 million increase from higher natural gas transportation margin; partially offset by
- \$8 million decrease due to the unfavorable impact of weather.

Operations and maintenance increased \$28 million, or 3%, for 2024 compared to 2023 primarily due to higher electric distribution costs of \$19 million, higher transmission costs from MISO of \$9 million and higher energy efficiency costs of \$8 million, partially offset by lower nuclear power generation costs of \$8 million.

Depreciation and amortization increased \$93 million, or 10%, for 2024 compared to 2023 primarily due to \$56 million related to new and repowered wind-powered generating facilities and other plant placed in-service, \$52 million from higher Iowa revenue sharing accruals and \$5 million from a regulatory mechanism that provides customers the retail energy benefits of certain wind-powered generation projects, partially offset by \$19 million from the write-off of certain assets in 2023.

Property and other taxes increased \$5 million, or 3%, for 2024 compared to 2023 primarily due to higher wind turbine property taxes.

Interest expense increased \$71 million, or 21%, for 2024 compared to 2023 primarily due to September 2023 and January 2024 long-term debt issuances.

Allowance for borrowed and equity funds increased \$12 million, or 15%, for 2024 compared to 2023 primarily due to higher construction work-in-progress balances related to wind- and solar-powered generation projects.

Other, net increased \$47 million, or 131%, for 2024 compared to 2023 primarily due to higher interest income and higher cash surrender values of corporate-owned life insurance policies.

Income tax benefit increased \$146 million, or 21%, for 2024 compared to 2023, and the effective tax rate was (512)% for 2024 and (240)% for 2023. The change in the effective tax rate was substantially due to an increase of \$129 million in PTCs. PTC's totaled \$810 million, \$681 million and \$710 million in 2024, 2023 and 2022, respectively.

Federal renewable electricity PTCs are earned as energy from qualifying wind- and solar-powered generating facilities is produced and sold and are based on a prescribed per-kilowatt rate pursuant to the applicable federal income tax law. Qualifying generating facilities are eligible for the credits for 10 years from the date the facilities are placed in-service. Beginning in late 2014, some of MidAmerican Energy's wind-powered generating facilities surpassed the 10-year eligibility period for earning the credits. Most of those facilities have since been repowered, and under IRS rules, qualifying repowered facilities are eligible for the available credits, for 10 years from the date they are returned to service. Refer to "Capital Expenditures" in Liquidity and Capital Resources for additional information about repowering and new wind- and solar-powered generation placed in-service.

Additionally, beginning in 2024, MidAmerican Energy's ownership of the Quad Cities Station qualifies for federal nuclear PTCs which provide a tax credit for qualifying production volumes subject to a phase-out based on annual gross receipts. Both the amount of the PTC and the gross receipt thresholds adjust annually for inflation over the duration of the program.

MidAmerican Funding -

Income tax benefit for MidAmerican Funding increased \$148 million, or 21%, for 2024 compared to 2023, and the effective tax rate was (570)% for 2024 and (244)% for 2023. The change in effective tax rates was due principally to the factors discussed for MidAmerican Energy.

Year Ended December 31, 2023 Compared to Year Ended December 31, 2022

MidAmerican Energy -

Electric utility margin decreased \$137 million, or 6%, for 2023 compared to 2022 primarily due to:

- \$223 million decrease in wholesale utility margin due to lower margin per unit of \$158 million, reflecting lower market prices, and lower volumes of \$65 million or 15.8%; and
- \$7 million decrease in Multi-Value Projects ("MVP") transmission revenue; partially offset by
- \$93 million increase in retail utility margin primarily due to \$75 million, net of energy costs, from higher recoveries through bill riders (offset in operations and maintenance expense and income tax benefit), \$30 million from higher customer usage, \$6 million due to price impacts from changes in sales mix and \$5 million from higher wind-turbine performance settlements, partially offset by \$23 million from the unfavorable impact of weather. Retail customer volumes increased 1.3%.

Natural gas utility margin decreased \$6 million, or 2%, for 2023 compared to 2022 primarily due to:

- \$19 million decrease due to the unfavorable impact of weather; and
- \$2 million decrease from lower refunds related to amortization of excess accumulated deferred income taxes arising from the federal tax rate change from 35% to 21% (offset in income tax benefit); partially offset by
- \$11 million increase in customer usage; and
- \$3 million increase in natural gas transportation margin, reflecting higher prices.

Operations and maintenance increased \$23 million, or 3%, for 2023 compared to 2022 primarily due to higher technology costs of \$11 million, higher nuclear power generation costs of \$8 million, higher employee costs of \$5 million, higher steam power generation costs of \$4 million, higher other power generation costs of \$4 million, higher property insurance costs of \$4 million and higher nonregulated operating costs of \$2 million, partially offset by lower electric distribution costs of \$15 million and lower transmission costs from MISO of \$4 million.

Depreciation and amortization decreased \$260 million, or 22%, for 2023 compared to 2022 primarily due to \$267 million from lower Iowa revenue sharing accruals and \$45 million from a regulatory mechanism that provides customers the retail energy benefits of certain wind-powered generation projects, partially offset by \$39 million related to new and repowered wind-powered generating facilities and other plant placed in-service and \$12 million from lower depreciation expense deferrals in 2023.

Property and other taxes increased \$12 million, or 8%, for 2023 compared to 2022 primarily due to \$9 million from higher wind turbine property taxes and \$3 million from higher replacement taxes.

Interest expense increased \$33 million, or 11%, for 2023 compared to 2022 primarily due to higher interest expense from a September 2023 long-term debt issuance and higher interest rates on variable rate long-term debt.

Allowance for borrowed and equity funds increased \$12 million, or 18%, for 2023 compared to 2022 primarily due to higher construction work-in-progress balances related to wind- and solar-powered generation projects.

Other, net increased \$36 million, or 100%, for 2023 compared to 2022 primarily due to higher cash surrender values of corporate-owned life insurance policies of \$39 million and higher interest income of \$16 million, partially offset by higher non-service costs of postretirement employee benefit plans.

Income tax benefit decreased \$77 million, or 10%, for 2023 compared to 2022, and the effective tax rate was (240)% for 2023 and (403)% for 2022. The change in the effective tax rate was substantially due to a decrease of \$29 million in PTCs, partially offset by state income tax impacts.

MidAmerican Funding -

Income tax benefit for MidAmerican Funding decreased \$81 million, or 10%, for 2023 compared to 2022, and the effective tax rate was (244)% for 2023 and (454)% for 2022. The change in effective tax rates was due principally to the factors discussed for MidAmerican Energy and higher pretax income from a one-time gain on the sale of an investment.

Liquidity and Capital Resources

As of December 31, 2024, MidAmerican Energy's and MidAmerican Funding's total net liquidity were as follows (in millions):

MidAmerican Energy:

Cash and cash equivalents	\$ 549
Credit facilities, maturing 2025 and 2027	1,505
Less:	
Tax-exempt bond support	(271)
Net credit facilities	1,234
MidAmerican Energy total net liquidity	<u>\$ 1,783</u>

MidAmerican Funding:

MidAmerican Energy total net liquidity	\$ 1,783
Cash and cash equivalents	3
MHC, Inc. credit facility, maturing 2025	4
MidAmerican Funding total net liquidity	<u>\$ 1,790</u>

Operating Activities

MidAmerican Energy's net cash flows from operating activities were \$1,978 million, \$2,217 million and \$2,174 million for 2024, 2023 and 2022, respectively. MidAmerican Funding's net cash flows from operating activities were \$1,967 million, \$2,203 million and \$2,161 million for 2024, 2023 and 2022, respectively. Cash flows from operating activities decreased for 2024 compared to 2023 primarily due to higher payments to vendors, lower utility margin for MidAmerican Energy's regulated electric business, higher interest payments and higher property tax payments, partially offset by higher income tax receipts, lower asset retirement obligation settlements and higher utility margin for MidAmerican Energy's regulated natural gas business. Cash flows from operating activities increased for 2023 compared to 2022 primarily due to lower asset retirement obligation settlements, higher utility margin for MidAmerican Energy's regulated electric business and higher income tax receipts, partially offset by higher payments to vendors and lower utility margin for MidAmerican Energy's regulated natural gas business.

The timing of MidAmerican Energy's income tax cash flows from period to period can be significantly affected by the estimated federal income tax payment methods selected and assumptions made for each payment date.

Investing Activities

MidAmerican Energy's net cash flows from investing activities were \$(1,691) million, \$(1,837) million and \$(1,867) million for 2024, 2023 and 2022, respectively. MidAmerican Funding's net cash flows from investing activities were \$(1,691) million, \$(1,825) million and \$(1,868) million for 2024, 2023 and 2022, respectively. Net cash flows from investing activities consist almost entirely of capital expenditures. Refer to "Future Uses of Cash" for further discussion of capital expenditures. Purchases and proceeds related to marketable securities primarily consist of activity within the Quad Cities Generating Station nuclear decommissioning trust and other trust investments.

Financing Activities

MidAmerican Energy's net cash flows from financing activities were \$(374) million, \$(6) million and \$(278) million for 2024, 2023 and 2022, respectively. MidAmerican Funding's net cash flows from financing activities were \$(361) million, \$(6) million and \$(262) million for 2024, 2023 and 2022, respectively. In 2024, 2023 and 2022, MidAmerican Energy paid \$425 million, \$1,025 million and \$275 million, respectively, in cash dividends to its parent company, MHC Inc. In 2024, 2023 and 2022, MidAmerican Funding paid \$425 million, \$1,025 million and \$69 million, respectively, in cash distributions to its sole member, BHE. Proceeds from long-term debt reflect MidAmerican Energy's issuance in January 2024 of \$600 million of its 5.30% First Mortgage Bonds due February 2055 and in September 2023 of \$350 million of its 5.350% First Mortgage Bonds due January 2034 and \$1 billion of its 5.850% First Mortgage Bonds due September 2054. In 2024 and 2023, MidAmerican Energy repaid \$539 million and \$317 million of long-term debt, respectively. MidAmerican Funding received \$13 million in 2024 and paid \$189 million in 2022 through its note payable with BHE.

Debt Authorizations and Related Matters

Short-term Debt

MidAmerican Energy has authority from the FERC to issue, through April 2, 2026, commercial paper and bank notes aggregating \$1.5 billion. MidAmerican Energy has a \$1.5 billion unsecured credit facility expiring in June 2027. The credit facility, which supports MidAmerican Energy's commercial paper program and its variable-rate tax-exempt bond obligations and provides for the issuance of letters of credit, has a variable interest rate based on the Secured Overnight Financing Rate, plus a spread that varies based on MidAmerican Energy's credit ratings for senior unsecured long-term debt securities. Additionally, MidAmerican Energy has a \$5 million unsecured credit facility for general corporate purposes.

Long-term Debt and Preferred Stock

MidAmerican Energy currently has an effective shelf registration statement with the SEC to issue an additional \$1.3 billion of long-term debt securities and preferred stock through March 10, 2026. MidAmerican Energy has authorization from the FERC to issue, through June 30, 2025, long-term debt securities up to an aggregate of \$1.05 billion and preferred stock up to an aggregate of \$500 million. MidAmerican Energy has authorization from the ICC through May 25, 2025, to issue long-term debt securities up to an aggregate of \$1.05 billion and preferred stock up to an aggregate of \$500 million.

MidAmerican Energy's mortgage dated September 9, 2013, creates a lien on most of MidAmerican Energy's electric utility property within the state of Iowa, allowing the issuance of bonds based on a percentage of eligible utility property additions, bond credits arising from retirement of previously outstanding bonds or deposits of cash. As of December 31, 2024, MidAmerican Energy estimated it would be able to issue up to \$8.9 billion of new first mortgage bonds under the mortgage. Any issuances are subject to market conditions, and amounts are further limited by regulatory authorizations and commitments, as well as any more restrictive requirements of covenants and tests contained in other financing agreements. MidAmerican Energy also has the ability to release property from the lien of the mortgage on the basis of property additions, bond credits or deposits of cash.

MidAmerican Funding or one of its subsidiaries, including MidAmerican Energy, may from time to time seek to acquire its outstanding debt securities through cash purchases in the open market, privately negotiated transactions or otherwise. Any debt securities repurchased by MidAmerican Funding or one of its subsidiaries may be reissued or resold by MidAmerican Funding or one of its subsidiaries from time to time and will depend on prevailing market conditions, the issuing company's liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

Future Uses of Cash

MidAmerican Energy and MidAmerican Funding have available a variety of sources of liquidity and capital resources, both internal and external, including net cash flows from operating activities, public and private debt offerings, the issuance of commercial paper, the use of unsecured revolving credit facilities, and other sources. These sources are expected to provide funds required for current operations, capital expenditures, debt retirements and other capital requirements. The availability and terms under which MidAmerican Energy and MidAmerican Funding have access to external financing depends on a variety of factors, including their credit ratings, investors' judgment of risk and conditions in the overall capital markets, including the condition of the utility industry.

Capital Expenditures

MidAmerican Energy has significant future capital requirements. Capital expenditure needs are reviewed regularly by management and may change significantly as a result of these reviews, which may consider, among other factors, impacts to customers' rates; changes in environmental and other rules and regulations; the impact of U.S. federal executive orders; outcomes of regulatory proceedings; changes in income tax laws; general business conditions; load projections; system reliability standards; the cost and efficiency of construction labor, equipment and materials; commodity prices; and the cost and availability of capital.

MidAmerican Energy's historical and forecast capital expenditures, each of which exclude amounts for non-cash equity AFUDC and other non-cash items, for the years ended December 31 are as follows (in millions):

	Historical			Forecast		
	2022	2023	2024	2025	2026	2027
Wind generation	\$ 685	\$ 744	\$ 507	\$ 783	\$ 945	\$ 1,150
Electric distribution	311	369	339	305	289	274
Electric transmission	145	205	245	239	294	371
Solar generation	119	13	3	14	152	492
Other	609	502	610	502	610	727
Total	<u>\$ 1,869</u>	<u>\$ 1,833</u>	<u>\$ 1,704</u>	<u>\$ 1,843</u>	<u>\$ 2,290</u>	<u>\$ 3,014</u>

MidAmerican Energy's capital expenditures provided above consist of the following:

- Wind generation includes the construction, acquisition, repowering and operation of wind-powered generating facilities in Iowa.
 - Construction of wind-powered generating facilities totaled \$127 million for 2024, \$608 million for 2023 and \$72 million for 2022. MidAmerican Energy placed in-service 200 MWs of new wind-powered generation in 2023. Planned spending for the construction of additional wind-powered generating facilities totals \$272 million, \$182 million and \$432 million for 2025, 2026 and 2027, respectively.
 - Repowering of wind-powered generating facilities totaled \$307 million for 2024, \$47 million for 2023 and \$500 million for 2022. Planned spending for repowering totals \$444 million, \$697 million and \$652 million in 2025, 2026 and 2027, respectively. MidAmerican Energy expects its repowered facilities to meet IRS guidelines for the re-establishment of PTCs under the prevailing wage and apprenticeship guidelines for 10 years from the date the facilities are placed in-service.
- Electric distribution includes expenditures for new facilities to meet retail demand growth and for replacement of existing facilities to maintain system reliability.
- Electric transmission includes expenditures to meet retail demand growth, upgrades to accommodate third-party generator requirements and replacement of existing facilities to maintain system reliability.
- Solar generation includes the construction and operation of solar-powered generating facilities, including 141 MWs of small- and utility-scale solar generation which was placed in-service in 2022, with total spend of \$3 million in 2024, \$13 million in 2023 and \$119 million in 2022. Planned spending for the construction and operation of additional solar-powered generating facilities totals \$14 million, \$152 million and \$492 million for 2025, 2026 and 2027, respectively.
- Remaining expenditures primarily relate to routine projects for other generation, natural gas distribution, technology, facilities and other operational needs to serve existing and expected demand.

Material Cash Requirements

MidAmerican Energy and MidAmerican Funding have cash requirements that may affect their financial condition that arise primarily from long- and short-term debt (refer to Notes 7 and 8), firm commitments (refer to Note 13) and construction and other development costs (refer to Liquidity and Capital Resources included within this Item 7) and AROs (refer to Note 11). Refer, where applicable, to the respective referenced note in Notes to Financial Statements in Item 8 of this Form 10-K for additional information.

MidAmerican Energy has cash requirements relating to interest payments of \$7.9 billion on long-term debt, including \$395 million due in 2025. Additionally, MidAmerican Funding has cash requirements relating to interest payments on its long-term debt of \$75 million, including \$17 million due in 2025.

Regulatory Matters

MidAmerican Energy is subject to comprehensive regulation. Refer to the discussion contained in Item 1 of this Form 10-K for further information regarding MidAmerican Energy's general regulatory framework and current regulatory matters.

Environmental Laws and Regulations

MidAmerican Energy is subject to federal, state and local laws and regulations regarding air quality, climate change, emissions performance standards, water quality, coal ash disposal and other environmental matters that have the potential to impact MidAmerican Energy's current and future operations. In addition to imposing continuing compliance obligations, these laws and regulations provide regulators with the authority to levy substantial penalties for noncompliance including fines, injunctive relief and other sanctions. These laws and regulations are administered by various federal, state and local agencies. MidAmerican Energy believes it is in material compliance with all applicable laws and regulations, although many are subject to interpretation that may ultimately be resolved by the courts. Environmental laws and regulations continue to evolve, and MidAmerican Energy is unable to predict the impact of the changing laws and regulations on its operations and financial results.

Refer to "Environmental Laws and Regulations" in Item 1 of this Form 10-K for further discussion regarding environmental laws and regulations.

Collateral and Contingent Features

Debt securities of MidAmerican Energy are rated by credit rating agencies. Assigned credit ratings are based on each rating agency's assessment of MidAmerican Energy's ability to, in general, meet the obligations of its issued debt securities. The credit ratings are not a recommendation to buy, sell or hold securities, and there is no assurance that a particular credit rating will continue for any given period of time. As of December 31, 2024, MidAmerican Energy's credit ratings for its senior secured debt and its issuer credit ratings for senior unsecured debt from the recognized credit rating agencies were investment grade. As a result of the issuance of first mortgage bonds by MidAmerican Energy in September 2013, its then outstanding senior unsecured debt was equally and ratably secured with such first mortgage bonds. Refer to Note 8 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K for a discussion of MidAmerican Energy's first mortgage bonds.

MidAmerican Funding and MidAmerican Energy have no credit rating downgrade triggers that would accelerate the maturity dates of its outstanding debt, and a change in ratings is not an event of default under the applicable debt instruments. MidAmerican Energy's unsecured revolving credit facilities do not require the maintenance of a minimum credit rating level in order to draw upon their availability. However, commitment fees and interest rates under the credit facilities are tied to credit ratings and increase or decrease when the ratings change. A ratings downgrade could also increase the future cost of commercial paper, short- and long-term debt issuances or new credit facilities.

In accordance with industry practice, certain wholesale agreements, including derivative contracts, contain credit support provisions that in part base MidAmerican Energy's collateral requirements on its credit ratings for senior unsecured debt as reported by one or more of the recognized credit rating agencies. These agreements may either specifically provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed specified rating-dependent threshold levels ("credit-risk-related contingent features") or provide the right for counterparties to demand "adequate assurance," or in some cases terminate the contract, in the event of a material adverse change in MidAmerican Energy's creditworthiness. These rights can vary by contract and by counterparty. If all credit-risk-related contingent features or adequate assurance provisions for these agreements had been triggered as of December 31, 2024, MidAmerican Energy would have been required to post \$96 million of additional collateral. MidAmerican Energy's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation, or other factors.

Inflation

Historically, overall inflation and changing prices in the economies where MidAmerican Energy operates have not had a significant impact on its financial results. MidAmerican Energy operates under cost-of-service based rate-setting structures administered by various state commissions and the FERC. Under these rate-setting structures, MidAmerican Energy is allowed to include prudent costs in its rates, including the impact of inflation. MidAmerican Energy attempts to minimize the potential impact of inflation on its operations through the use of fuel, energy and other cost adjustment clauses and bill riders, by employing prudent risk management and hedging strategies and by considering, among other areas, inflation's impact on purchases of energy, operating expenses, materials and equipment costs, contract negotiations, future capital spending programs, and long-term debt issuances. There can be no assurance that such actions will be successful.

New Accounting Pronouncements

For a discussion of new accounting pronouncements affecting MidAmerican Energy and MidAmerican Funding, refer to Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Critical Accounting Estimates

Certain accounting measurements require management to make estimates and judgments concerning transactions that will be settled several years in the future. Amounts recognized on the Financial Statements based on such estimates involve numerous assumptions subject to varying and potentially significant degrees of judgment and uncertainty and will likely change in the future as additional information becomes available. The following critical accounting estimates are impacted significantly by MidAmerican Energy's methods, judgments and assumptions used in the preparation of the Financial Statements and should be read in conjunction with MidAmerican Energy's Summary of Significant Accounting Policies included in Note 2 of Notes to Financial Statements in Item 8 of this Form 10-K.

Accounting for the Effects of Certain Types of Regulation

MidAmerican Energy prepares its financial statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, MidAmerican Energy defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in regulated rates occur.

MidAmerican Energy continually evaluates the applicability of the guidance for regulated operations and whether its regulatory assets and liabilities are probable of inclusion in future regulated rates by considering factors such as a change in the regulator's approach to setting rates from cost-based ratemaking to another form of regulation, other regulatory actions or the impact of competition, that could limit MidAmerican Energy's ability to recover its costs. MidAmerican Energy believes its application of the guidance for regulated operations is appropriate, and its existing regulatory assets and liabilities are probable of inclusion in future regulated rates. The evaluation reflects the current political and regulatory climate at both the federal and state levels. If it becomes no longer probable that the deferred costs or income will be included in future regulated rates, the related regulatory assets and liabilities will be written off to net income, returned to customers or re-established as AOCI. Total regulatory assets were \$622 million and total regulatory liabilities were \$1,264 million as of December 31, 2024. Refer to Note 5 of Notes to Financial Statements in Item 8 of this Form 10-K for additional information regarding regulatory assets and liabilities.

Impairment of Goodwill

MidAmerican Funding's Consolidated Balance Sheet as of December 31, 2024, includes goodwill from the acquisition of MHC totaling \$1.3 billion. Goodwill is allocated to each reporting unit. MidAmerican Funding evaluates goodwill for impairment at least annually and completed its annual review as of October 31, 2024. Additionally, no indicators of impairment were identified as of December 31, 2024. Significant judgment is required in estimating the fair value of the reporting unit and performing goodwill impairment tests. MidAmerican Funding uses a variety of methods to estimate a reporting unit's fair value, principally discounted projected future net cash flows. Key assumptions used include, but are not limited to, the use of estimated future cash flows; multiples of earnings; and an appropriate discount rate. Estimated future cash flows are impacted by, among other factors, growth rates, changes in regulations and rates, ability to renew contracts and estimates of future commodity prices. In estimating future cash flows, MidAmerican Funding incorporates current market information, as well as historical factors.

Pension and Other Postretirement Benefits

MidAmerican Energy sponsors defined benefit pension and other postretirement benefit plans that cover the majority of the employees of BHE and its domestic energy subsidiaries other than PacifiCorp and NV Energy Inc. MidAmerican Energy recognizes the funded status of its defined benefit pension and other postretirement benefit plans on the Balance Sheets. Funded status is the fair value of plan assets minus the benefit obligation as of the measurement date. As of December 31, 2024, MidAmerican Energy recognized net assets totaling \$37 million for the funded status of its defined benefit pension and other postretirement benefit plans. As of December 31, 2024, amounts not yet recognized as a component of net periodic benefit cost that were included in regulatory assets and regulatory liabilities totaled \$17 million and \$73 million, respectively.

The expense and benefit obligations relating to these defined benefit pension and other postretirement benefit plans are based on actuarial valuations. Inherent in these valuations are key assumptions, including, but not limited to, discount rates, expected long-term rate of return on plan assets and healthcare cost trend rates. These key assumptions are reviewed annually and modified as appropriate. MidAmerican Energy believes that the key assumptions utilized in recording obligations under the plans are reasonable based on prior plan experience and current market and economic conditions. Refer to Note 10 of Notes to Financial Statements in Item 8 of this Form 10-K for disclosures about MidAmerican Energy's defined benefit pension and other postretirement benefit plans, including the key assumptions used to calculate the funded status and net periodic benefit cost for these plans as of and for the year ended December 31, 2024.

MidAmerican Energy chooses a discount rate based upon high quality debt security investment yields in effect as of the measurement date that corresponds to cash flows over the expected benefit period. The pension and other postretirement benefit liabilities increase as the discount rate is reduced.

In establishing its assumption as to the expected long-term rate of return on plan assets, MidAmerican Energy utilizes the expected asset allocation and return assumptions for each asset class based on historical performance and forward-looking views of the financial markets. Pension and other postretirement benefits expense increases as the expected long-term rate of return on plan assets decreases. MidAmerican Energy regularly reviews its actual asset allocations and rebalances its investments to its targeted allocations when considered appropriate.

MidAmerican Energy chooses a healthcare cost trend rate that reflects the near and long-term expectations of increases in medical costs and corresponds to the expected benefit payment periods. The healthcare cost trend rate is assumed to gradually decline to 5.00% by 2033 at which point the rate of increase is assumed to remain constant.

The key assumptions used may differ materially from period to period due to changing market and economic conditions. These differences may result in a significant impact to pension and other postretirement benefits expense and funded status. If changes were to occur for the following key assumptions, the approximate effect on the Financial Statements of the total plan before allocations to affiliates would be as follows (in millions):

	Pension Plans		Other Postretirement Benefit Plans	
	+0.5%	-0.5%	+0.5%	-0.5%
Effect on December 31, 2024 Benefit Obligations:				
Discount rate	\$ (20)	\$ 22	\$ (7)	\$ 8
Effect on 2024 Periodic Cost:				
Discount rate	1	(1)	—	—
Expected rate of return on plan assets	(2)	2	(1)	1

A variety of factors affect the funded status of the plans, including discount rates, asset returns, plan changes and MidAmerican Energy's funding policy for each plan.

Income Taxes

In determining MidAmerican Funding's and MidAmerican Energy's income taxes, management is required to interpret complex income tax laws and regulations, which includes consideration of regulatory implications imposed by MidAmerican Energy's various regulatory commissions. MidAmerican Funding's and MidAmerican Energy's income tax returns are subject to continuous examinations by federal, state and local tax authorities that may give rise to different interpretations of these complex laws and regulations. Due to the nature of the examination process, it generally takes years before these examinations are completed and these matters are resolved. MidAmerican Funding and MidAmerican Energy recognize the tax benefit from an uncertain tax position only if it is more-likely-than-not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the Consolidated Financial Statements from such a position are measured based on the largest benefit that is more-likely-than-not to be realized upon ultimate settlement. Although the ultimate resolution of their federal, state and local tax examinations is uncertain, each company believes it has made adequate provisions for its income tax positions. The aggregate amount of any additional income tax liabilities that may result from these examinations is not expected to have a material impact on its consolidated financial results. Refer to Note 9 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding income taxes.

It is probable that MidAmerican Energy will either refund to, or recover from its customers in certain state jurisdiction income tax benefits and expense related to the federal tax rate change from 35% to 21%, certain property-related basis differences, and other various differences. As of December 31, 2024, these amounts were recognized as a net regulatory liability of \$47 million and will be included in regulated rates when the temporary differences reverse.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

MidAmerican Energy's Balance Sheets include assets and liabilities with fair values that are subject to market risks. MidAmerican Energy's significant market risks are primarily associated with commodity prices, interest rates and the extension of credit to counterparties with which it transacts. The following discussion addresses the significant market risks associated with MidAmerican Energy's business activities. MidAmerican Energy has established guidelines for credit risk management. Refer to Note 2 of Notes to Financial Statements in Item 8 of this Form 10-K for additional information regarding MidAmerican Energy's contracts accounted for as derivatives.

Commodity Price Risk

MidAmerican Energy is exposed to the impact of market fluctuations in commodity prices and interest rates. MidAmerican Energy is principally exposed to electricity, natural gas, coal and fuel oil commodity price risk as it has an obligation to serve retail customer load in its regulated service territory. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather; market liquidity; generating facility availability; customer usage; storage; and transmission and transportation constraints. Commodity price risk for MidAmerican Energy's regulated retail electricity and natural gas operations is significantly mitigated by the inclusion of energy costs in energy cost rider mechanisms, which permit the current recovery of such costs from its retail customers. MidAmerican Energy uses commodity derivative contracts, which may include forwards, futures, options, swaps and other agreements to mitigate price volatility on behalf of its customers. MidAmerican Energy does not engage in a material amount of proprietary trading activities.

Interest Rate Risk

MidAmerican Energy and MidAmerican Funding are exposed to interest rate risk on their outstanding variable-rate short- and long-term debt and future debt issuances. MidAmerican Energy and MidAmerican Funding manage interest rate risk by limiting their exposure to variable interest rates primarily through the issuance of fixed-rate long-term debt and by monitoring market changes in interest rates. As a result of the fixed interest rates, the fixed-rate long-term debt does not expose MidAmerican Energy or MidAmerican Funding to the risk of loss due to changes in market interest rates. Additionally, because fixed-rate long-term debt is not carried at fair value on the Consolidated Balance Sheets, changes in fair value would impact earnings and cash flows only if MidAmerican Energy or MidAmerican Funding were to reacquire all or a portion of these instruments prior to their maturity. MidAmerican Energy or MidAmerican Funding may from time to time enter into interest rate derivative contracts, such as interest rate swaps or locks, to mitigate their exposure to interest rate risk. The nature and amount of their short- and long-term debt can be expected to vary from period to period as a result of future business requirements, market conditions and other factors. Refer to Notes 7, 8 and 12 of Notes to Consolidated Financial Statements in Item 1 of this Form 10-K for additional discussion of MidAmerican Energy's and MidAmerican Funding's short- and long-term debt.

As of December 31, 2024 and 2023, MidAmerican Energy had short- and long-term variable-rate obligations totaling \$271 million and \$306 million, respectively, that expose MidAmerican Energy to the risk of increased interest expense in the event of increases in short-term interest rates. The market risk related to MidAmerican Energy's variable-rate debt as of December 31, 2024, is not hedged. If variable interest rates were to increase by 10% from December 31 levels, it would not have a material effect on MidAmerican Energy's annual interest expense. The carrying value of the variable-rate obligations approximates fair value as of December 31, 2024 and 2023.

Credit Risk

MidAmerican Energy is exposed to counterparty credit risk associated with wholesale energy supply and marketing activities with other utilities, energy marketing companies, financial institutions and other market participants. Additionally, MidAmerican Energy participates in the RTO markets and has indirect credit exposure related to other participants, although RTO credit policies are designed to limit exposure to credit losses from individual participants. Credit risk may be concentrated to the extent MidAmerican Energy's counterparties have similar economic, industry or other characteristics and due to direct or indirect relationships among the counterparties. Before entering into a transaction, MidAmerican Energy analyzes the financial condition of each significant wholesale counterparty, establishes limits on the amount of unsecured credit to be extended to each counterparty, and evaluates the appropriateness of unsecured credit limits on an ongoing basis. To further mitigate wholesale counterparty credit risk, MidAmerican Energy enters into netting and collateral arrangements that may include margining and cross-product netting agreements and obtains third-party guarantees, letters of credit and cash deposits. If required, MidAmerican Energy exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

Substantially all of MidAmerican Energy's electric wholesale sales revenue results from participation in RTOs, including the MISO and the PJM. MidAmerican Energy's share of historical losses from defaults by other RTO market participants has not been material. Additionally, as of December 31, 2024, MidAmerican Energy's aggregate direct credit exposure from electric wholesale marketing counterparties was not material.

Item 8. Financial Statements and Supplementary Data

MidAmerican Energy Company

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MidAmerican Funding, LLC and Subsidiaries

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
MidAmerican Energy Company
Des Moines, Iowa

Opinion on the Financial Statements

We have audited the accompanying balance sheets of MidAmerican Energy Company ("MidAmerican Energy") as of December 31, 2024 and 2023, the related statements of operations, changes in shareholder's equity, and cash flows for each of the three years in the period ended December 31, 2024, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of MidAmerican Energy as of December 31, 2024 and 2023, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2024, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of MidAmerican Energy's management. Our responsibility is to express an opinion on MidAmerican Energy's financial statements 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 MidAmerican Energy 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. MidAmerican Energy is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of MidAmerican Energy's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the 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 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 financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the executive committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the 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.

Regulatory Matters — Effects of Rate Regulation on the Financial Statements — Refer to Note 5 to the financial statements

Critical Audit Matter Description

MidAmerican Energy is subject to rate regulation by state public service commissions as well as the Federal Energy Regulatory Commission (collectively, the "Commissions"), which have jurisdiction with respect to the rates of electric and natural gas companies in the respective service territories where MidAmerican Energy operates. Management has determined its regulated operations meet the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the specialized rules to account for the effects of cost-based rate regulation. Accounting for the economic effects of rate regulation has a pervasive effect on the financial statements.

Regulated rates are subject to regulatory rate-setting processes. Rates are determined, approved, and established based on a cost-of-service basis, which is designed to allow MidAmerican Energy an opportunity to recover its prudently incurred costs of providing services and to earn a reasonable return on its invested capital. Regulatory decisions can have an effect on the recovery of costs, the rate of return earned on investment, and the timing and amount of assets to be recovered by rates. While MidAmerican Energy has indicated it expects to recover costs from customers through regulated rates, there is a risk that changes to the Commissions' approach to setting rates or other regulatory actions could limit MidAmerican Energy's ability to recover its costs.

We identified the effects of rate regulation on the financial statements as a critical audit matter due to the significant judgments made by management to support its assertions about affected account balances and disclosures and the high degree of subjectivity involved in assessing the impact of regulatory orders on the financial statements. Management judgments include assessing the likelihood of (1) recovery in future rates of incurred costs, (2) a disallowance of part of the cost of recently completed plant or plant under construction, and (3) a refund to customers. Given that management's accounting judgments are based on assumptions about the outcome of decisions by the Commissions, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate setting process due to its inherent complexities.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the uncertainty of decisions by the Commissions included the following, among others:

- We evaluated MidAmerican Energy's disclosures related to the effects of rate regulation by testing recorded balances and evaluating regulatory developments.
- We read relevant regulatory orders issued by the Commissions, regulatory statutes, filings made by MidAmerican Energy and intervenors, and other external information. We evaluated relevant external information and compared it to certain recorded regulatory asset and liability balances for completeness.
- For certain regulatory matters, we inspected MidAmerican Energy's filings with the Commissions and the filings with the Commissions by intervenors to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedents of the Commissions' treatment of similar costs under similar circumstances.
- We inquired of management about property, plant, and equipment that may be abandoned. We inquired of management to identify projects that are designed to replace assets that may be retired prior to the end of the useful life. We inspected minutes of the board of directors and regulatory orders and other filings with the Commissions to identify any evidence that may contradict management's assertion regarding probability of an abandonment.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
February 21, 2025

We have served as MidAmerican Energy's auditor since 1999.

MIDAMERICAN ENERGY COMPANY
BALANCE SHEETS
(Amounts in millions)

	As of December 31,	
	2024	2023
ASSETS		
Current assets:		
Cash and cash equivalents	\$ 549	\$ 636
Trade receivables, net	230	272
Income tax receivable	2	1
Inventories	369	364
Prepayments	117	113
Other current assets	63	39
Total current assets	1,330	1,425
Property, plant and equipment, net	22,765	21,970
Regulatory assets	622	600
Investments and restricted investments	1,147	1,030
Other assets	252	210
Total assets	\$ 26,116	\$ 25,235

The accompanying notes are an integral part of these financial statements.

MIDAMERICAN ENERGY COMPANY
BALANCE SHEETS (continued)
(Amounts in millions)

	As of December 31,	
	2024	2023
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities:		
Accounts payable	\$ 375	\$ 543
Accrued interest	117	106
Accrued property, income and other taxes	192	197
Current portion of long-term debt	17	539
Other current liabilities	91	102
Total current liabilities	792	1,487
Long-term debt	8,807	8,227
Regulatory liabilities	1,264	1,079
Deferred income taxes	3,626	3,494
Asset retirement obligations	823	768
Other long-term liabilities	623	577
Total liabilities	15,935	15,632
Commitments and contingencies (Note 13)		
Shareholder's equity:		
Common stock - 350 shares authorized, no par value, 71 shares issued and outstanding	—	—
Additional paid-in capital	561	561
Retained earnings	9,620	9,042
Total shareholder's equity	10,181	9,603
Total liabilities and shareholder's equity	\$ 26,116	\$ 25,235

The accompanying notes are an integral part of these financial statements.

MIDAMERICAN ENERGY COMPANY
STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2024	2023	2022
Operating revenue:			
Regulated electric	\$ 2,584	\$ 2,673	\$ 2,988
Regulated natural gas and other	667	720	1,037
Total operating revenue	3,251	3,393	4,025
Operating expenses:			
Cost of fuel and energy	430	501	679
Cost of natural gas purchased for resale and other	367	451	763
Operations and maintenance	879	851	828
Depreciation and amortization	1,001	908	1,168
Property and other taxes	166	161	149
Total operating expenses	2,843	2,872	3,587
Operating income	408	521	438
Other income (expense):			
Interest expense	(417)	(346)	(313)
Allowance for borrowed funds	25	19	15
Allowance for equity funds	65	59	51
Other, net	83	36	—
Total other income (expense)	(244)	(232)	(247)
Income before income tax expense (benefit)	164	289	191
Income tax expense (benefit)	(839)	(693)	(770)
Net income	\$ 1,003	\$ 982	\$ 961

The accompanying notes are an integral part of these financial statements.

MIDAMERICAN ENERGY COMPANY
STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY
(Amounts in millions)

	Common Stock	Additional Paid-in Capital	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2021	\$ —	\$ 561	\$ 8,399	\$ 8,960
Net income	—	—	961	961
Common stock dividends	—	—	(275)	(275)
Other equity transactions	—	—	(1)	(1)
Balance, December 31, 2022	—	561	9,084	9,645
Net income	—	—	982	982
Common stock dividends	—	—	(1,025)	(1,025)
Other equity transactions	—	—	1	1
Balance, December 31, 2023	—	561	9,042	9,603
Net income	—	—	1,003	1,003
Common stock dividends	—	—	(425)	(425)
Balance, December 31, 2024	<u>\$ —</u>	<u>\$ 561</u>	<u>\$ 9,620</u>	<u>\$ 10,181</u>

The accompanying notes are an integral part of these financial statements.

MIDAMERICAN ENERGY COMPANY
STATEMENTS OF CASH FLOWS
(Amounts in millions)

	Years Ended December 31,		
	2024	2023	2022
Cash flows from operating activities:			
Net income	\$ 1,003	\$ 982	\$ 961
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	1,001	908	1,168
Amortization of utility plant to other operating expenses	35	34	35
Allowance for equity funds	(65)	(59)	(51)
Deferred income taxes and amortization of investment tax credits	81	90	33
Settlements of asset retirement obligations	(1)	(21)	(85)
Other, net	19	46	51
Changes in other operating assets and liabilities:			
Trade receivables and other assets	15	254	(11)
Inventories	(5)	(87)	(43)
Pension and other postretirement benefit plans, net	2	3	8
Accrued property, income and other taxes, net	(18)	76	40
Accounts payable and other liabilities	(89)	(9)	68
Net cash flows from operating activities	<u>1,978</u>	<u>2,217</u>	<u>2,174</u>
Cash flows from investing activities:			
Capital expenditures	(1,704)	(1,833)	(1,869)
Purchases of marketable securities	(327)	(243)	(499)
Proceeds from sales of marketable securities	313	227	492
Other investment proceeds	12	—	2
Other, net	15	12	7
Net cash flows from investing activities	<u>(1,691)</u>	<u>(1,837)</u>	<u>(1,867)</u>
Cash flows from financing activities:			
Common stock dividends	(425)	(1,025)	(275)
Proceeds from long-term debt	592	1,338	—
Repayments of long-term debt	(539)	(317)	(2)
Other, net	(2)	(2)	(1)
Net cash flows from financing activities	<u>(374)</u>	<u>(6)</u>	<u>(278)</u>
Net change in cash and cash equivalents and restricted cash and cash equivalents	(87)	374	29
Cash and cash equivalents and restricted cash and cash equivalents at beginning of year	642	268	239
Cash and cash equivalents and restricted cash and cash equivalents at end of year	<u>\$ 555</u>	<u>\$ 642</u>	<u>\$ 268</u>

The accompanying notes are an integral part of these financial statements.

MIDAMERICAN ENERGY COMPANY NOTES TO FINANCIAL STATEMENTS

(1) Organization and Operations

MidAmerican Energy Company ("MidAmerican Energy") is a public utility with electric and natural gas operations and is the principal subsidiary of MHC Inc. ("MHC"). MHC is a holding company that conducts no business other than the ownership of its subsidiaries. MHC's nonregulated subsidiary is Midwest Capital Group, Inc. MHC is the direct wholly owned subsidiary of MidAmerican Funding, LLC ("MidAmerican Funding"), which is an Iowa limited liability company with Berkshire Hathaway Energy Company ("BHE") as its sole member. BHE is a holding company based in Des Moines, Iowa, that has investments in subsidiaries principally engaged in energy businesses. BHE is a wholly owned subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway").

(2) Summary of Significant Accounting Policies

Basis of Presentation

The Statements of Comprehensive Income have been omitted as net income equals comprehensive income for the years ended December 31, 2024, 2023 and 2022.

Use of Estimates in Preparation of Financial Statements

The preparation of the Financial Statements in conformity with accounting principles generally accepted in the United States of America ("GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the period. These estimates include, but are not limited to, the effects of regulation; certain assumptions made in accounting for pension and other postretirement benefits; asset retirement obligations ("AROs"); income taxes; unbilled revenue; valuation of certain financial assets and liabilities, including derivative contracts; and accounting for contingencies. Actual results may differ from the estimates used in preparing the Financial Statements.

Accounting for the Effects of Certain Types of Regulation

MidAmerican Energy's utility operations are subject to the regulation of the Iowa Utilities Commission ("IUC"), the Illinois Commerce Commission ("ICC"), the South Dakota Public Utilities Commission, and the Federal Energy Regulatory Commission ("FERC"). MidAmerican Energy's accounting policies and the accompanying Financial Statements conform to GAAP applicable to rate-regulated enterprises and reflect the effects of the ratemaking process.

MidAmerican Energy prepares its financial statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, MidAmerican Energy defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in regulated rates occur. If it becomes no longer probable that the deferred costs or income will be included in future regulated rates, the related regulatory assets and liabilities will be written off to net income, returned to customers or re-established as accumulated other comprehensive income (loss) ("AOCI").

Fair Value Measurements

As defined under GAAP, fair value is the price that would be received to sell an asset or paid to transfer a liability between market participants in the principal market or in the most advantageous market when no principal market exists. Adjustments to transaction prices or quoted market prices may be required in illiquid or disorderly markets in order to estimate fair value. Different valuation techniques may be appropriate under the circumstances to determine the value that would be received to sell an asset or paid to transfer a liability in an orderly transaction. Market participants are assumed to be independent, knowledgeable, able and willing to transact an exchange and not under duress. Nonperformance or credit risk is considered when determining fair value. Considerable judgment may be required in interpreting market data used to develop the estimates of fair value. Accordingly, estimates of fair value presented herein are not necessarily indicative of the amounts that could be realized in a current or future market exchange.

Cash and Cash Equivalents and Restricted Cash and Cash Equivalents

Cash equivalents consist of funds invested in money market mutual funds, U.S. Treasury Bills and other investments with a maturity of three months or less when purchased. Cash and cash equivalents exclude amounts where availability is restricted by legal requirements, loan agreements or other contractual provisions. Restricted cash and cash equivalents consist substantially of funds restricted for wildlife preservation. A reconciliation of cash and cash equivalents and restricted cash and cash equivalents as of December 31, 2024 and 2023 as presented on the Statements of Cash Flows is outlined below and disaggregated by the line items in which they appear on the Balance Sheets (in millions):

	As of December 31,	
	2024	2023
Cash and cash equivalents	\$ 549	\$ 636
Restricted cash and cash equivalents in other current assets	6	6
Total cash and cash equivalents and restricted cash and cash equivalents	<u>\$ 555</u>	<u>\$ 642</u>

Investments

Fixed Maturity Securities

MidAmerican Energy's management determines the appropriate classification of investments in fixed maturity securities at the acquisition date and reevaluates the classification at each balance sheet date. Investments that management does not intend to use or is restricted from using in current operations are presented as noncurrent on the Balance Sheets.

Available-for-sale investments are carried at fair value with realized gains and losses, as determined on a specific identification basis, recognized in earnings and unrealized gains and losses recognized in AOCI, net of tax. Realized and unrealized gains and losses on fixed maturity securities in a trust related to the decommissioning of the Quad Cities Generating Station Units 1 and 2 ("Quad Cities Station") are recorded as a net regulatory liability because MidAmerican Energy expects to refund to customers any decommissioning funds in excess of costs for these activities through regulated rates. Trading investments are carried at fair value with changes in fair value recognized in earnings. Held-to-maturity securities are carried at amortized cost, reflecting the ability and intent to hold the securities to maturity. The difference between the original cost and maturity value of a fixed maturity security is amortized to earnings using the interest method.

Investments gains and losses arise when investments are sold (as determined on a specific identification basis) or are other-than-temporarily impaired with respect to securities classified as available-for-sale. If the value of a fixed maturity investment declines to below amortized cost and the decline is deemed other than temporary, the amortized cost of the investment is reduced to fair value, with a corresponding charge to earnings. Any resulting impairment loss is recognized in earnings if MidAmerican Energy intends to sell, or expects to be required to sell, the debt security before its amortized cost is recovered. If MidAmerican Energy does not expect to ultimately recover the amortized cost basis even if it does not intend to sell the security, the credit loss component is recognized in earnings and any difference between fair value and the amortized cost basis, net of the credit loss, is reflected in other comprehensive income (loss) ("OCI"). For regulated investments, any impairment charge is offset by the establishment of a regulatory asset to the extent recovery in regulated rates is probable.

Equity Securities

All changes in fair value of equity securities in a trust related to the decommissioning of nuclear generation assets are recorded as a net regulatory liability since MidAmerican Energy expects to refund to customers any decommissioning funds in excess of costs for these activities through regulated rates.

Allowance for Credit Losses

Trade receivables are primarily short-term in nature with stated collection terms of less than one year from the date of origination and are stated at the outstanding principal amount, net of an estimated allowance for credit losses. The allowance for credit losses is based on MidAmerican Energy's assessment of the collectability of amounts owed to it by its customers. This assessment requires judgment regarding the ability of customers to pay or the outcome of any pending disputes. In measuring the allowance for credit losses for trade receivables, MidAmerican Energy primarily utilizes credit loss history. However, it may adjust the allowance for credit losses to reflect current conditions and reasonable and supportable forecasts that deviate from historical experience. The changes in the balance of the allowance for credit losses, which is included in trade receivables, net on the Balance Sheets, is summarized as follows for the years ended December 31 (in millions):

	2024	2023	2022
Beginning balance	\$ 12	\$ 14	\$ 12
Charged to operating costs and expenses, net	8	8	11
Write-offs, net	(9)	(10)	(9)
Ending balance	<u>\$ 11</u>	<u>\$ 12</u>	<u>\$ 14</u>

Derivatives

MidAmerican Energy employs a number of different derivative contracts, including forwards, futures, options, swaps and other agreements, to manage price risk for electricity, natural gas and other commodities, and interest rate risk. Derivative contracts are recorded on the Balance Sheets as either assets or liabilities and are stated at estimated fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by GAAP. Derivative balances reflect offsetting permitted under master netting agreements with counterparties and cash collateral paid or received under such agreements. Cash collateral received from or paid to counterparties to secure derivative contract assets or liabilities in excess of amounts offset is included in other current assets on the Balance Sheets.

Commodity derivatives used in normal business operations that are settled by physical delivery, among other criteria, are eligible for and may be designated as normal purchases or normal sales. Normal purchases or normal sales contracts are not marked to market, and settled amounts are recognized as operating revenue or cost of sales on the Statements of Operations.

For MidAmerican Energy's derivatives not designated as hedging contracts, the settled amount is generally included in regulated rates. Accordingly, the net unrealized gains and losses associated with interim price movements on contracts that are accounted for as derivatives and probable of inclusion in regulated rates are recorded as regulatory assets and liabilities.

Inventories

Inventories consist mainly of materials and supplies, totaling \$249 million and \$240 million as of December 31, 2024 and 2023, respectively, coal stocks, totaling \$86 million and \$89 million as of December 31, 2024 and 2023, respectively, and natural gas in storage, totaling \$29 million and \$29 million as of December 31, 2024 and 2023, respectively. The cost of materials and supplies, coal stocks and fuel oil is determined using the average cost method. The cost of stored natural gas is determined using the last-in-first-out method. With respect to stored natural gas, the replacement cost would be \$18 million and \$4 million higher as of December 31, 2024 and 2023, respectively.

Property, Plant and Equipment, Net

General

Additions to utility plant are recorded at cost. MidAmerican Energy capitalizes all construction-related material, direct labor and contract services, as well as indirect construction costs. Indirect construction costs include debt allowance for funds used during construction ("AFUDC") and equity AFUDC. The cost of additions and betterments are capitalized, while costs incurred that do not improve or extend the useful lives of the related assets are generally expensed. Additionally, MidAmerican Energy has regulatory arrangements in Iowa in which the carrying cost of certain utility plant has been reduced for amounts associated with electric returns on equity exceeding specified thresholds and retail energy benefits associated with certain wind-powered generation. Amounts expensed under these arrangements are included as a component of depreciation and amortization.

Depreciation and amortization for MidAmerican Energy's utility operations are computed by applying the composite or straight-line method based on either estimated useful lives or mandated recovery periods as prescribed by its various regulatory authorities. Depreciation studies are completed by MidAmerican Energy to determine the appropriate group lives, net salvage and group depreciation rates. These studies are reviewed and rates are ultimately approved by the applicable regulatory commission. Net salvage includes the estimated future residual values of the assets and any estimated removal costs recovered through approved depreciation rates. Estimated removal costs are recorded as either a cost of removal regulatory liability or an ARO liability on the Balance Sheets, depending on whether the obligation meets the requirements of an ARO. As actual removal costs are incurred, the associated liability is reduced.

Generally, when MidAmerican Energy retires or sells a component of utility plant, it charges the original cost, net of any proceeds from the disposition to accumulated depreciation. Any gain or loss on disposals of nonregulated assets is recorded through earnings.

Debt and equity AFUDC, which represent the estimated costs of debt and equity funds necessary to finance the construction of its regulated facilities, is capitalized by MidAmerican Energy as a component of utility plant, with offsetting credits to the Statements of Operations. AFUDC is computed based on guidelines set forth by the FERC. After construction is completed, MidAmerican Energy is permitted to earn a return on these costs as a component of the related assets, as well as recover these costs through depreciation expense over the useful lives of the related assets.

Asset Retirement Obligations

MidAmerican Energy recognizes AROs when it has a legal obligation to perform decommissioning or removal activities upon retirement of an asset. MidAmerican Energy's AROs are primarily related to decommissioning of the Quad Cities Station and obligations associated with its other generating facilities. The fair value of an ARO liability is recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made, and is added to the carrying amount of the associated asset, which is then depreciated over the remaining useful life of the asset. Subsequent to the initial recognition, the ARO liability is adjusted for any revisions to the original estimate of undiscounted cash flows (with corresponding adjustments to utility plant) and for accretion of the ARO liability due to the passage of time. The difference between the ARO liability, the corresponding ARO asset included in utility plant, net and amounts recovered in rates to satisfy such liabilities is recorded as a regulatory asset or liability.

Impairment

MidAmerican Energy evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or when the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. Additionally, when evaluating the carrying value of regulated assets, MidAmerican Energy considers the impact of regulation on recoverability. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value and any resulting impairment loss is reflected on the Statements of Operations.

Revenue Recognition

MidAmerican Energy uses a single five-step model to identify and recognize revenue from contracts with customers ("Customer Revenue") upon transfer of control of promised goods or services in an amount that reflects the consideration to which MidAmerican Energy expects to be entitled in exchange for those goods and services. MidAmerican Energy records sales, franchise and excise taxes collected directly from customers and remitted directly to the taxing authorities on a net basis on the Statements of Operations.

A majority of MidAmerican Energy's energy revenue is derived from tariff-based sales arrangements approved by various regulatory commissions. These tariff-based revenues are mainly comprised of energy, transmission, distribution and natural gas and have performance obligations to deliver energy products and services to customers which are satisfied over time as energy is delivered or services are provided.

Revenue from electric and natural gas customers is recognized as electricity or natural gas is delivered or services are provided. Revenue recognized includes billed and unbilled amounts. As of December 31, 2024 and 2023, unbilled revenue was \$109 million and \$97 million, respectively, and is included in trade receivables, net on the Balance Sheets.

The determination of customer billings is based on a systematic reading of customer meters and applicable rates. At the end of each month, amounts of energy provided to customers since the date of the last meter reading are estimated, and the corresponding unbilled revenue is recorded. Factors that can impact the estimate of unbilled revenue include, but are not limited to, seasonal weather patterns, total volumes supplied to the system, line losses and composition of customer classes. Unbilled revenue is reversed in the following month and billed revenue is recorded based on the subsequent meter readings.

All of MidAmerican Energy's regulated retail electric and natural gas sales are subject to energy adjustment clauses. MidAmerican Energy also has costs that are recovered, at least in part, through bill riders, including demand-side management and certain transmission costs. The clauses and riders allow MidAmerican Energy to adjust the amounts charged for electric and natural gas service as the related costs change. The costs recovered in revenue through use of the adjustment clauses and bill riders are charged to expense in the same year the related revenue is recognized. At any given time, these costs may be over or under collected from customers. The total over collection included in trade receivables, net at December 31, 2024, was \$16 million and the total under collection included in trade receivables, net at December 31, 2023, was \$29 million.

Unamortized Debt Premiums, Discounts and Issuance Costs

Premiums, discounts and issuance costs incurred for the issuance of long-term debt are amortized over the term of the related financing using the effective interest method.

Income Taxes

Berkshire Hathaway includes MidAmerican Funding and MidAmerican Energy in its consolidated U.S. federal and Iowa state income tax returns. MidAmerican Funding's and MidAmerican Energy's provisions for income taxes have been computed on a stand-alone basis.

Deferred income tax assets and liabilities are based on differences between the financial statement and income tax basis of assets and liabilities using enacted income tax rates expected to be in effect for the year in which the differences are expected to reverse. Changes in deferred income tax assets and liabilities associated with certain property-related basis differences and other various differences that MidAmerican Energy deems probable to be passed on to its customers in most state jurisdictions are charged or credited directly to a regulatory asset or liability and will be included in regulated rates when the temporary differences reverse. Other changes in deferred income tax assets and liabilities are included as a component of income tax expense. Changes in deferred income tax assets and liabilities attributable to changes in enacted income tax rates are charged or credited to income tax expense or a regulatory asset or liability in the period of enactment. Valuation allowances are established when necessary to reduce deferred income tax assets to the amount that is more-likely-than-not to be realized.

Investment tax credits are deferred and amortized over the estimated useful lives of the related properties or as prescribed by various regulatory commissions.

MidAmerican Funding and MidAmerican Energy recognize the tax benefit from an uncertain tax position only if it is more-likely-than-not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the Consolidated Financial Statements from such a position are measured based on the largest benefit that is more-likely-than-not to be realized upon ultimate settlement. MidAmerican Funding's and MidAmerican Energy's unrecognized tax benefits are primarily included in taxes accrued and other long-term liabilities on their respective Consolidated Balance Sheets. Estimated interest and penalties, if any, related to uncertain tax positions are included as a component of income tax expense (benefit) on the Consolidated Statements of Operations.

New Accounting Pronouncements

In November 2023, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2023-07, Segment Reporting Topic 280, "Segment Reporting—Improvements to Reportable Segment Disclosures" which allows disclosure of one or more measures of segment profit or loss used by the chief operating decision maker to allocate resources and assess performance. Additionally, the standard requires enhanced disclosures of significant segment expenses and other segment items as well as incremental qualitative disclosures on both an annual and interim basis. This guidance is effective for annual reporting periods beginning after December 15, 2023, and interim reporting periods after December 15, 2024. Early adoption is permitted and retrospective application is required for all periods presented. MidAmerican Energy adopted this guidance for the fiscal year beginning January 1, 2024 under the retrospective method. The adoption did not have a material impact on MidAmerican Energy's Financial Statements but did increase the disclosures included within Notes to Financial Statements. Refer to Note 19 for additional disclosures of certain significant segment expenses.

In December 2023, the FASB issued ASU No. 2023-09, Income Taxes Topic 740, "Income Tax—Improvements to Income Tax Disclosures" which requires enhanced disclosures, including specific categories and disaggregation of information in the effective tax rate reconciliation, disaggregated information related to income taxes paid, income or loss from continuing operations before income tax expense or benefit, and income tax expense or benefit from continuing operations. This guidance is effective for annual reporting periods beginning after December 15, 2024. Early adoption is permitted and should be applied on a prospective basis, however retrospective application is permitted. MidAmerican Energy is currently evaluating the impact of adopting this guidance on its Financial Statements and disclosures included within Notes to Financial Statements.

In November 2024, the FASB issued ASU No. 2024-03, Income Statement—Reporting Comprehensive Income—Expense Disaggregation Disclosures Subtopic 220-40, "Disaggregation of Income Statement Expenses" which addresses requests from investors for more detailed information about certain expenses and requires disclosure of the amounts of purchases of inventory, employee compensation, depreciation and intangible asset amortization included in each relevant expense caption presented on the income statement. This guidance is effective for annual reporting periods beginning after December 15, 2026 and interim reporting periods beginning after December 15, 2027. Early adoption is permitted and should be applied on a prospective basis, however retrospective application is permitted. MidAmerican Energy is currently evaluating the impact of adopting this guidance on its Consolidated Financial Statements and disclosures included within Notes to Financial Statements.

(3) Property, Plant and Equipment, Net

Property, plant and equipment, net consists of the following as of December 31 (in millions):

	Depreciable Life	2024	2023
Utility plant:			
Generation	20-62 years	\$ 18,446	\$ 18,129
Transmission	55-80 years	3,029	2,834
Electric distribution	15-80 years	5,890	5,288
Natural gas distribution	30-75 years	2,413	2,294
Utility plant in-service		29,778	28,545
Accumulated depreciation and amortization		(8,572)	(7,841)
Utility plant in-service, net		21,206	20,704
Nonregulated property, net of accumulated depreciation and amortization	20-50 years	6	6
		21,212	20,710
Construction work-in-progress		1,553	1,260
Property, plant and equipment, net		<u>\$ 22,765</u>	<u>\$ 21,970</u>

Nonregulated property, net consists primarily of land not recoverable for regulated utility purposes.

The average depreciation and amortization rates applied to depreciable utility plant for the years ended December 31 were as follows:

	2024	2023	2022
Electric	3.1 %	3.3 %	3.2 %
Natural gas	3.0 %	2.8 %	2.9 %

Under a revenue sharing arrangement in Iowa, MidAmerican Energy accrues throughout the year a regulatory liability based on the extent to which its anticipated annual equity return exceeds specified thresholds, with an equal amount recorded in depreciation and amortization expense. The annual regulatory liability accrual reduces utility plant upon final determination of the amount. For the years ended December 31, 2024, 2023 and 2022, \$81 million, \$29 million, and \$296 million, respectively, is reflected in depreciation and amortization expense on the Statements of Operations.

(4) Jointly Owned Utility Facilities

Under joint facility ownership agreements with other utilities, MidAmerican Energy, as a tenant in common, has undivided interests in jointly owned generation and transmission facilities. MidAmerican Energy accounts for its proportionate share of each facility, and each joint owner has provided financing for its share of each facility. Operating costs of each facility are assigned to joint owners based on their percentage of ownership or energy production, depending on the nature of the cost. Operating expenses on the Statements of Operations include MidAmerican Energy's share of the expenses of these facilities.

The amounts shown in the table below represent MidAmerican Energy's share in each jointly owned facility included in property, plant and equipment, net as of December 31, 2024 (dollars in millions):

	Company Share	Plant in Service	Accumulated Depreciation and Amortization	Construction Work-in- Progress
Louisa No. 1	88 %	\$ 988	\$ 559	\$ 7
Quad Cities Nos. 1 and 2 ⁽¹⁾	25	747	501	13
Walter Scott, Jr. No. 3	79	1,033	679	10
Walter Scott, Jr. No. 4 ⁽²⁾	60	177	124	12
George Neal No. 4	41	337	199	5
Ottumwa No. 1 ⁽²⁾	52	402	306	16
George Neal No. 3	72	598	368	13
Transmission facilities	Various	276	103	4
Total		<u>\$ 4,558</u>	<u>\$ 2,839</u>	<u>\$ 80</u>

(1) Includes amounts related to nuclear fuel.

(2) Plant in-service and accumulated depreciation and amortization amounts are net of credits applied under Iowa regulatory arrangements totaling \$953 million and \$218 million, respectively.

(5) Regulatory Matters

Regulatory Assets

Regulatory assets represent costs that are expected to be recovered in future regulated rates. MidAmerican Energy's regulatory assets reflected on the Balance Sheets consist of the following as of December 31 (in millions):

	Weighted Average Remaining Life	2024	2023
Asset retirement obligations ⁽¹⁾	14 years	\$ 546	\$ 541
Employee benefit plans ⁽²⁾	9 years	17	16
Demand side management	1 year	16	—
Unrealized loss on regulated derivative contracts	1 year	13	11
Other	Various	30	32
Total		<u>\$ 622</u>	<u>\$ 600</u>

(1) Amount predominantly relates to AROs for fossil-fueled and wind-powered generating facilities. Refer to Note 11 for a discussion of AROs.

(2) Represents amounts not yet recognized as a component of net periodic benefit cost that are expected to be included in regulated rates when recognized.

MidAmerican Energy had regulatory assets not earning a return on investment of \$620 million and \$598 million as of December 31, 2024 and 2023, respectively.

Regulatory Liabilities

Regulatory liabilities represent amounts expected to be returned to customers in future periods. MidAmerican Energy's regulatory liabilities reflected on the Balance Sheets consist of the following as of December 31 (in millions):

	Weighted Average Remaining Life	2024	2023
Cost of removal ⁽¹⁾	28 years	\$ 452	\$ 411
Asset retirement obligations ⁽²⁾	29 years	443	360
Iowa electric revenue sharing ⁽³⁾	Various	186	127
Employee benefit plans ⁽⁴⁾	N/A	73	16
Deferred income taxes ⁽⁵⁾	Various	47	102
Pre-funded AFUDC on transmission MVPs ⁽⁶⁾	55 years	33	32
Other	Various	30	31
Total		<u>\$ 1,264</u>	<u>\$ 1,079</u>

- (1) Amounts represent estimated costs, as accrued through depreciation rates and exclusive of ARO liabilities, of removing utility plant in accordance with accepted regulatory practices. Amounts are deducted from rate base or otherwise accrue a carrying cost.
- (2) Amount represents the excess of nuclear decommission trust assets over the related ARO. Refer to Note 11 for a discussion of AROs.
- (3) Represents accruals associated with a regulatory arrangement in Iowa in which equity returns exceeding specified thresholds reduce utility plant and retail electric energy cost recoveries as required.
- (4) Represents amounts not yet recognized as a component of net periodic benefit cost that are to be returned to customers in future periods when recognized.
- (5) Amounts primarily represent income tax liabilities primarily related to the federal tax rate change from 35% to 21% that are probable to be passed on to customers, offset by income tax benefits related to state accelerated tax depreciation and certain property-related basis differences that were previously passed on to customers and will be included in regulated rates when the temporary differences reverse.
- (6) Represents AFUDC accrued on transmission MVPs that is deducted from rate base as a result of the inclusion of related construction work-in-progress in rate base.

(6) Investments and Restricted Investments

Investments and restricted investments consists of the following amounts as of December 31 (in millions):

	2024	2023
Nuclear decommissioning trust	\$ 871	\$ 767
Rabbi trusts	252	239
Other	24	24
Total	<u>\$ 1,147</u>	<u>\$ 1,030</u>

MidAmerican Energy has established a trust for the investment of funds for decommissioning the Quad Cities Station. The debt and equity securities in the trust are reported at fair value. Funds are invested in the trust in accordance with applicable federal and state investment guidelines and are restricted for use as reimbursement for costs of decommissioning the Quad Cities Station, which is currently licensed for operation until December 2032. As of December 31, 2024 and 2023, the fair value of the trust's funds was invested as follows: 55% and 56%, respectively, in domestic common equity securities, 31% and 33%, respectively, in U.S. government securities, 13% and 9%, respectively, in domestic corporate debt securities and 1% and 2%, respectively, in other securities.

Rabbi trusts primarily hold corporate-owned life insurance on certain current and former key executives and directors. The Rabbi trusts were established to hold investments used to fund the obligations of various nonqualified executive and director compensation plans and to pay the costs of the trusts. The amount represents the cash surrender value of all of the policies included in the Rabbi trusts, net of amounts borrowed against the cash surrender value. Changes in the cash surrender value of the policies are reflected in other income (expense) - other, net on the Statements of Operations.

(7) Short-term Debt and Credit Facilities

Interim financing of working capital needs and the construction program is obtained from unaffiliated parties through the sale of commercial paper or short-term borrowing from banks. The following table summarizes MidAmerican Energy's availability under its unsecured revolving credit facilities as of December 31 (in millions):

	2024	2023
Credit facilities	\$ 1,505	\$ 1,505
Less:		
Variable-rate tax-exempt bond support	(271)	(306)
Net credit facilities	<u>\$ 1,234</u>	<u>\$ 1,199</u>

As of December 31, 2024, MidAmerican Energy has a \$1.5 billion unsecured credit facility expiring in June 2027 with an unlimited number of maturity extension options, subject to lender consent. The credit facility, which supports MidAmerican Energy's commercial paper program and its variable-rate tax-exempt bond obligations and provides for the issuance of letters of credit, has a variable interest rate based on the Secured Overnight Financing Rate ("SOFR") or a base rate, at MidAmerican Energy's option, plus a spread that varies based on MidAmerican Energy's credit ratings for senior unsecured long-term debt securities. Additionally, MidAmerican Energy has a \$5 million unsecured credit facility, which expires June 2025 and has a variable interest rate based on SOFR, plus a spread.

MidAmerican Energy had no commercial paper borrowings outstanding as of December 31, 2024 and 2023. The \$1.5 billion credit facility requires that MidAmerican Energy's ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.65 to 1.0 as of the last day of any quarter.

As of December 31, 2024, MidAmerican Energy was in compliance with the covenants of its credit facilities. MidAmerican Energy has authority from the FERC to issue commercial paper and bank notes aggregating \$1.5 billion through April 2, 2026.

As of December 31, 2024 and 2023, MidAmerican Energy had \$135 million and \$345 million, respectively, of letter of credit capacity under its \$1.5 billion unsecured credit facility, of which no amounts were outstanding. Additionally, as of December 31, 2024 and 2023, MidAmerican Energy had \$53 million and \$55 million, respectively, of letters of credit outstanding outside of its \$1.5 billion unsecured credit facility in support of certain transactions required by third parties that generally have provisions that automatically extend the annual expiration dates for an additional year unless the issuing bank elects not to renew a letter of credit prior to the expiration date.

(8) Long-term Debt

MidAmerican Energy's long-term debt consists of the following, including amounts maturing within one year and unamortized premiums, discounts and debt issuance costs, as of December 31 (dollars in millions):

	Par Value	2024	2023
First mortgage bonds:			
3.50%, due 2024	\$ —	\$ —	\$ 500
3.10%, due 2027	375	374	374
3.65%, due 2029	850	857	858
5.35%, due 2034	350	347	347
4.80%, due 2043	350	347	347
4.40%, due 2044	400	396	396
4.25%, due 2046	450	446	446
3.95%, due 2047	475	471	471
3.65%, due 2048	700	690	690
4.25%, due 2049	900	876	876
3.15%, due 2050	600	593	592
2.70%, due 2052	500	493	492
5.85%, due 2054	1,000	990	989
5.30%, due 2055	600	592	—
Notes:			
6.75% Series, due 2031	400	398	398
5.75% Series, due 2035	300	299	299
5.80% Series, due 2036	350	348	348
Transmission upgrade obligations, 3.303% to 7.896%, due 2036 to 2043	66	37	39
Variable-rate tax-exempt bond obligation series: (weighted average interest rate-2024-3.359%, 2023-4.807%):			
Due 2024	—	—	35
Due 2025	13	13	13
Due 2036	33	33	33
Due 2038	45	45	45
Due 2046	30	30	29
Due 2047	150	149	149
Total long-term debt	<u>\$ 8,937</u>	<u>\$ 8,824</u>	<u>\$ 8,766</u>

Reflected as:

	2024	2023
Current portion of long-term debt	\$ 17	\$ 539
Long-term debt	8,807	8,227
Total long-term debt	<u>\$ 8,824</u>	<u>\$ 8,766</u>

The annual repayments of MidAmerican Energy's long-term debt for the years beginning January 1, 2025, and thereafter, excluding unamortized premiums, discounts and debt issuance costs, are as follows (in millions):

2025	\$ 17
2026	4
2027	379
2028	4
2029	854
2030 and thereafter	7,679

Pursuant to MidAmerican Energy's mortgage dated September 9, 2013, MidAmerican Energy's first mortgage bonds, currently and from time to time outstanding, are secured by a first mortgage lien on substantially all of its electric generating, transmission and distribution property within the state of Iowa, subject to certain exceptions and permitted encumbrances. Approximately \$25 billion of MidAmerican Energy's eligible property, based on original cost, was subject to the lien of the mortgage as of December 31, 2024. Additionally, MidAmerican Energy's senior notes outstanding are equally and ratably secured with the first mortgage bonds as required by the indentures under which the senior notes were issued.

MidAmerican Energy's variable-rate tax-exempt bond obligations bear interest at rates that are periodically established through remarketing of the bonds in the short-term tax-exempt market. MidAmerican Energy, at its option, may change the mode of interest calculation for these bonds by selecting from among several floating or fixed rate alternatives. The interest rates shown in the table above are the weighted average interest rates as of December 31, 2024 and 2023. MidAmerican Energy maintains revolving credit facility agreements to provide liquidity for holders of these issues. Additionally, MidAmerican Energy's obligations associated with the \$30 million and \$150 million variable rate, tax-exempt bond obligations due 2046 and 2047, respectively, are secured by an equal amount of first mortgage bonds pursuant to MidAmerican Energy's mortgage dated September 9, 2013, as supplemented and amended.

As of December 31, 2024, MidAmerican Energy was in compliance with all of its applicable long-term debt covenants.

In March 1999, MidAmerican Energy committed to the IUC to use commercially reasonable efforts to maintain an investment grade rating on its long-term debt and to maintain its common equity level above 42% of total capitalization unless circumstances beyond its control result in the common equity level decreasing to below 39% of total capitalization. MidAmerican Energy must seek the approval from the IUC of a reasonable utility capital structure if MidAmerican Energy's common equity level decreases below 42% of total capitalization, unless the decrease is beyond the control of MidAmerican Energy. MidAmerican Energy is also required to seek the approval of the IUC if MidAmerican Energy's equity level decreases to below 39%, even if the decrease is due to circumstances beyond the control of MidAmerican Energy. As of December 31, 2024, MidAmerican Energy's common equity ratio was 51% computed on a basis consistent with its commitment. As a result of its regulatory commitment to maintain its common equity level above certain thresholds, MidAmerican Energy could dividend \$3.8 billion as of December 31, 2024, without falling below 42%.

(9) Income Taxes

MidAmerican Energy's income tax expense (benefit) consists of the following for the years ended December 31 (in millions):

	2024	2023	2022
Current:			
Federal	\$ (885)	\$ (755)	\$ (769)
State	(35)	(28)	(34)
	(920)	(783)	(803)
Deferred:			
Federal	80	109	77
State	2	(18)	(43)
	82	91	34
Investment tax credits	(1)	(1)	(1)
Total	<u>\$ (839)</u>	<u>\$ (693)</u>	<u>\$ (770)</u>

A reconciliation of the federal statutory income tax rate to MidAmerican Energy's effective income tax rate applicable to income before income tax expense (benefit) is as follows for the years ended December 31:

	<u>2024</u>	<u>2023</u>	<u>2022</u>
Federal statutory income tax rate	21 %	21 %	21 %
Income tax credits	(495)	(236)	(372)
State income tax, net of federal income tax impacts	(16)	(12)	(32)
Effects of ratemaking	(20)	(12)	(23)
Other, net	(2)	(1)	3
Effective income tax rate	<u>(512)%</u>	<u>(240)%</u>	<u>(403)%</u>

Income tax credits relate primarily to production tax credits ("PTC") earned by MidAmerican Energy's wind- and solar-powered generating facilities. Federal renewable electricity PTCs are earned as energy from qualifying wind- and solar-powered generating facilities is produced and sold and are based on a per-kilowatt hour rate pursuant to the applicable federal income tax law. Wind- and solar-powered generating facilities are eligible for the credits for 10 years from the date the qualifying generating facilities are placed in-service. PTCs recognized for the years ended December 31, 2024, 2023 and 2022 totaled \$810 million, \$681 million and \$710 million, respectively.

MidAmerican Energy's net deferred income tax liability consists of the following as of December 31 (in millions):

	<u>2024</u>	<u>2023</u>
Deferred income tax assets:		
Regulatory liabilities	\$ 249	\$ 218
Asset retirement obligations	216	204
State carryforwards	66	68
Revenue sharing	47	34
Employee benefits	10	25
Other	80	68
Total deferred income tax assets	<u>668</u>	<u>617</u>
Valuation allowances	(2)	(2)
Total deferred income tax assets, net	<u>666</u>	<u>615</u>
Deferred income tax liabilities:		
Property-related items	(4,154)	(3,972)
Regulatory assets	(134)	(134)
Other	(4)	(3)
Total deferred income tax liabilities	<u>(4,292)</u>	<u>(4,109)</u>
Net deferred income tax liability	<u>\$ (3,626)</u>	<u>\$ (3,494)</u>

As of December 31, 2024, MidAmerican Energy's state tax carryforwards, principally related to \$981 million of net operating losses, expire at various intervals between 2025 and 2046.

The U.S. Internal Revenue Service has closed or effectively settled its examination of MidAmerican Energy's income tax returns through December 31, 2013. The statute of limitations for MidAmerican Energy's income tax returns have expired for certain states through December 31, 2011, and for other states through December 31, 2020, except for the impact of any federal audit adjustments. The closure of examinations, or the expiration of the statute of limitations, for state filings may not preclude the state from adjusting the state net operating loss carryforward utilized in a year for which the statute of limitations is not closed.

A reconciliation of the beginning and ending balances of MidAmerican Energy's net unrecognized tax benefits is as follows for the years ended December 31 (in millions):

	<u>2024</u>	<u>2023</u>
Beginning balance	\$ 22	\$ 16
Additions based on tax positions related to the current year	5	10
Interest	2	1
Reductions based on tax positions related to the current year	(7)	(5)
Ending balance	<u>\$ 22</u>	<u>\$ 22</u>

As of December 31, 2024, MidAmerican Energy had unrecognized tax benefits totaling \$52 million that, if recognized, would have an impact on the effective tax rate. The remaining unrecognized tax benefits relate to tax positions for which ultimate deductibility is highly certain but for which there is uncertainty as to the timing of such deductibility. Recognition of these tax benefits, other than applicable interest and penalties, would not affect MidAmerican Energy's effective income tax rate.

(10) Employee Benefit Plans

Defined Benefit Plan

MidAmerican Energy sponsors a noncontributory defined benefit pension plan covering a majority of all employees of BHE and its domestic energy subsidiaries other than PacifiCorp and NV Energy, Inc. Benefit obligations under the plan are based on a cash balance arrangement for salaried employees and most union employees and final average pay formulas for other union employees. MidAmerican Energy also maintains noncontributory, nonqualified defined benefit supplemental executive retirement plans ("SERP") for certain active and retired participants. In 2024 and 2022, the defined benefit pension plan recorded a curtailment gain of \$1 million and \$10 million, respectively, as a result of certain plan amendments. In 2023 and 2022, the defined benefit pension plan recorded a settlement gain of \$3 million and a settlement loss of \$4 million, respectively, for previously unrecognized gains and losses as a result of excess lump sum distributions over the defined threshold.

MidAmerican Energy also sponsors certain postretirement healthcare and life insurance benefits covering substantially all retired employees of BHE and its domestic energy subsidiaries other than PacifiCorp and NV Energy, Inc. Under the plans, a majority of all employees of the participating companies may become eligible for these benefits if they reach retirement age. New employees are not eligible for benefits under the plans. MidAmerican Energy has been allowed to recover accrued pension and other postretirement benefit costs in its electric and gas service rates.

Net Periodic Benefit Cost

For purposes of calculating the expected return on pension plan assets, a market-related value is used. The market-related value of plan assets is calculated by spreading the difference between expected and actual investment returns on equity investments over a five-year period beginning after the first year in which they occur.

MidAmerican Energy bills to and is reimbursed currently for affiliates' share of the net periodic benefit costs from all plans in which such affiliates participate. In 2024, 2023 and 2022, MidAmerican Energy's share of the pension net periodic benefit cost was \$(4) million, \$(5) million and \$(2) million, respectively. MidAmerican Energy's share of the other postretirement net periodic benefit cost in 2024, 2023 and 2022 totaled \$1 million, \$2 million and \$(2) million, respectively.

Net periodic benefit cost for the plans of MidAmerican Energy and the aforementioned affiliates included the following components for the years ended December 31 (in millions):

	Pension			Other Postretirement		
	2024	2023	2022	2024	2023	2022
Service cost	\$ 9	\$ 10	\$ 15	\$ 5	\$ 5	\$ 8
Interest cost	31	32	23	13	13	8
Expected return on plan assets	(31)	(30)	(27)	(16)	(14)	(14)
Curtailment	(1)	—	(10)	—	—	—
Settlement	—	(3)	4	—	—	—
Net amortization	(1)	—	1	1	—	(2)
Net periodic benefit cost	<u>\$ 7</u>	<u>\$ 9</u>	<u>\$ 6</u>	<u>\$ 3</u>	<u>\$ 4</u>	<u>\$ —</u>

Funded Status

The following table is a reconciliation of the fair value of plan assets for the years ended December 31 (in millions):

	Pension		Other Postretirement	
	2024	2023	2024	2023
Plan assets at fair value, beginning of year	\$ 516	\$ 490	\$ 278	\$ 240
Employer contributions	7	7	3	3
Participant contributions	—	—	1	1
Actual return on plan assets	45	64	41	51
Benefits paid	(46)	(45)	(17)	(17)
Plan assets at fair value, end of year	<u>\$ 522</u>	<u>\$ 516</u>	<u>\$ 306</u>	<u>\$ 278</u>

The following table is a reconciliation of the benefit obligations for the years ended December 31 (in millions):

	Pension		Other Postretirement	
	2024	2023	2024	2023
Benefit obligation, beginning of year	\$ 598	\$ 586	\$ 241	\$ 243
Service cost	9	10	5	5
Interest cost	31	32	13	13
Participant contributions	—	—	1	1
Actuarial (gain) loss	(17)	15	(24)	(4)
Amendment	(3)	—	—	—
Benefits paid	(46)	(45)	(17)	(17)
Benefit obligation, end of year	<u>\$ 572</u>	<u>\$ 598</u>	<u>\$ 219</u>	<u>\$ 241</u>
Accumulated benefit obligation, end of year	<u>\$ 542</u>	<u>\$ 564</u>		

The funded status of the plans and the amounts recognized on the Balance Sheets as of December 31 are as follows (in millions):

	Pension		Other Postretirement	
	2024	2023	2024	2023
Plan assets at fair value, end of year	\$ 522	\$ 516	\$ 306	\$ 278
Less - Benefit obligation, end of year	572	598	219	241
Funded status	<u>\$ (50)</u>	<u>\$ (82)</u>	<u>\$ 87</u>	<u>\$ 37</u>
Amounts recognized on the Balance Sheets:				
Other assets	\$ 29	\$ 3	\$ 87	\$ 37
Other current liabilities	(7)	(8)	—	—
Other long-term liabilities	(72)	(77)	—	—
Amounts recognized	<u>\$ (50)</u>	<u>\$ (82)</u>	<u>\$ 87</u>	<u>\$ 37</u>

The SERP has no plan assets; however, MidAmerican Energy and BHE have Rabbi trusts that hold corporate-owned life insurance and other investments to provide funding for the future cash requirements of the SERP. The cash surrender value of all of the policies included in MidAmerican Energy's Rabbi trusts, net of amounts borrowed against the cash surrender value, plus the fair market value of other Rabbi trust investments, was \$157 million and \$149 million as of December 31, 2024 and 2023, respectively. These assets are not included in the plan assets in the above table, but are reflected in investments and restricted investments on the Balance Sheets. The projected and accumulated benefit obligations for the SERP were \$79 million and \$85 million at December 31, 2024 and 2023, respectively.

Unrecognized Amounts

The portion of the funded status of the plans not yet recognized in net periodic benefit cost as of December 31 is as follows (in millions):

	Pension		Other Postretirement	
	2024	2023	2024	2023
Net gain	\$ (49)	\$ (19)	\$ (79)	\$ (30)
Prior service (credit) cost	(5)	(3)	17	18
Total	<u>\$ (54)</u>	<u>\$ (22)</u>	<u>\$ (62)</u>	<u>\$ (12)</u>

MidAmerican Energy sponsors pension and other postretirement benefit plans on behalf of certain of its affiliates in addition to itself, and therefore, the portion of the funded status of the respective plans that has not yet been recognized in net periodic benefit cost is attributable to multiple entities. Additionally, substantially all of MidAmerican Energy's portion of such amounts is either refundable to or recoverable from its customers and is reflected as regulatory liabilities and regulatory assets.

A reconciliation of the amounts not yet recognized as components of net periodic benefit cost for the years ended December 31, 2024 and 2023 is as follows (in millions):

	Regulatory Asset	Regulatory Liability	Receivables (Payables) with Affiliates	Total
<u>Pension</u>				
Balance, December 31, 2022	\$ 14	\$ (1)	\$ (20)	\$ (7)
Net loss (gain) arising during the year	2	(22)	2	(18)
Settlement	—	3	—	3
Total	2	(19)	2	(15)
Balance, December 31, 2023	16	(20)	(18)	(22)
Net loss (gain) arising during the year	1	(22)	(9)	(30)
Net prior service credit arising during the year	—	—	(3)	(3)
Net amortization	—	—	1	1
Total	1	(22)	(11)	(32)
Balance, December 31, 2024	<u>\$ 17</u>	<u>\$ (42)</u>	<u>\$ (29)</u>	<u>\$ (54)</u>

	Regulatory Asset	Regulatory Liability	Receivables (Payables) with Affiliates	Total
<u>Other Postretirement</u>				
Balance, December 31, 2022	\$ 33	\$ —	\$ (3)	\$ 30
Net (gain) loss arising during the year	(33)	3	(11)	(41)
Net amortization	—	1	(2)	(1)
Total	(33)	4	(13)	(42)
Balance, December 31, 2023	—	4	(16)	(12)
Net gain arising during the year	—	(35)	(14)	(49)
Net amortization	—	—	(1)	(1)
Total	—	(35)	(15)	(50)
Balance, December 31, 2024	<u>\$ —</u>	<u>\$ (31)</u>	<u>\$ (31)</u>	<u>\$ (62)</u>

Plan Assumptions

Assumptions used to determine benefit obligations and net periodic benefit cost were as follows:

	Pension			Other Postretirement		
	2024	2023	2022	2024	2023	2022
Benefit obligations as of December 31:						
Discount rate	5.75 %	5.45 %	5.70 %	5.70 %	5.45 %	5.60 %
Rate of compensation increase	3.00 %	3.00 %	3.00 %	N/A	N/A	N/A
Interest crediting rates for cash balance plan						
2022	N/A	N/A	3.74 %	N/A	N/A	N/A
2023	N/A	3.50 %	3.74 %	N/A	N/A	N/A
2024	3.81 %	3.50 %	3.74 %	N/A	N/A	N/A
2025	3.81 %	3.50 %	3.74 %	N/A	N/A	N/A
2026	3.81 %	3.50 %	3.74 %	N/A	N/A	N/A
2027 and beyond	3.81 %	3.50 %	3.74 %	N/A	N/A	N/A
Net periodic benefit cost for the years ended December 31:						
Discount rate	5.45 %	5.70 %	3.05 %	5.45 %	5.60 %	2.95 %
Expected return on plan assets ⁽¹⁾	6.55 %	6.35 %	4.30 %	6.65 %	6.80 %	5.30 %
Rate of compensation increase	3.00 %	3.00 %	2.75 %	N/A	N/A	N/A
Interest crediting rates for cash balance plan	3.81 %	3.50 %	3.74 %	N/A	N/A	N/A

(1) Amounts reflected are pretax values. Assumed after-tax returns for a taxable, non-union other postretirement plan were 5.45% for 2024, 5.52% for 2023 and 4.21% for 2022.

In establishing its assumption as to the expected return on plan assets, MidAmerican Energy utilizes the asset allocation and return assumptions for each asset class based on historical performance and forward-looking views of the financial markets.

	2024	2023
Assumed healthcare cost trend rates as of December 31:		
Healthcare cost trend rate assumed for next year	7.00 %	6.20 %
Rate that the cost trend rate gradually declines to	5.00 %	5.00 %
Year that the rate reaches the rate it is assumed to remain at	2033	2028

Contributions and Benefit Payments

Employer contributions to the pension and other postretirement benefit plans are expected to be \$7 million and \$1 million, respectively, during 2025. Funding to MidAmerican Energy's qualified pension benefit plan trust is based upon the actuarially determined costs of the plan and the requirements of the Internal Revenue Code, the Employee Retirement Income Security Act of 1974 and the Pension Protection Act of 2006, as amended. MidAmerican Energy considers contributing additional amounts from time to time in order to achieve certain funding levels specified under the Pension Protection Act of 2006, as amended. MidAmerican Energy evaluates a variety of factors, including funded status, income tax laws and regulatory requirements, in determining contributions to its other postretirement benefit plans.

Net periodic benefit costs assigned to MidAmerican Energy affiliates are reimbursed currently in accordance with its intercompany administrative services agreement. The expected benefit payments to participants in MidAmerican Energy's pension and other postretirement benefit plans for 2025 through 2029 and for the five years thereafter are summarized below (in millions):

	Projected Benefit Payments	
	Pension	Other Postretirement
2025	\$ 55	\$ 22
2026	54	22
2027	52	22
2028	50	22
2029	49	22
2030-2034	223	96

Plan Assets

Investment Policy and Asset Allocations

MidAmerican Energy's investment policy for its pension and other postretirement benefit plans is to balance risk and return through a diversified portfolio of debt securities, equity securities and other alternative investments. Maturities for debt securities are managed to targets consistent with prudent risk tolerances. The plans retain outside investment consultants to advise on plan investments within the parameters outlined by the Berkshire Hathaway Energy Company Investment Committee. The investment portfolio is managed in line with the investment policy with sufficient liquidity to meet near-term benefit payments.

The target allocations (percentage of plan assets) for MidAmerican Energy's pension and other postretirement benefit plan assets are as follows as of December 31, 2024:

	Pension	Other Postretirement
	%	%
Debt securities ⁽¹⁾	40-60	20-40
Equity securities ⁽¹⁾	30-60	60-80
Other	0-15	0-5

- (1) For purposes of target allocation percentages and consistent with the plans' investment policy, investment funds are allocated based on the underlying investments in debt and equity securities.

Fair Value Measurements

The following table presents the fair value of plan assets, by major category, for MidAmerican Energy's defined benefit pension plan (in millions):

	Input Levels for Fair Value Measurements ⁽¹⁾			
	Level 1	Level 2	Level 3	Total
<u>As of December 31, 2024:</u>				
Cash equivalents	\$ —	\$ 11	\$ —	\$ 11
Debt securities:				
U.S. government obligations	27	—	—	27
Corporate obligations	—	117	—	117
Municipal obligations	—	5	—	5
Agency, asset and mortgage-backed obligations	—	15	—	15
Equity securities:				
U.S. companies	53	—	—	53
International companies	1	—	—	1
Total assets in the fair value hierarchy	<u>\$ 81</u>	<u>\$ 148</u>	<u>\$ —</u>	229
Investment funds ⁽²⁾ measured at net asset value				293
Total assets measured at fair value				<u>\$ 522</u>
<u>As of December 31, 2023:</u>				
Cash equivalents	\$ —	\$ 11	\$ —	\$ 11
Debt securities:				
U.S. government obligations	25	—	—	25
Corporate obligations	—	110	—	110
Municipal obligations	—	6	—	6
Agency, asset and mortgage-backed obligations	—	14	—	14
Equity securities:				
U.S. companies	65	—	—	65
International companies	1	—	—	1
Total assets in the fair value hierarchy	<u>\$ 91</u>	<u>\$ 141</u>	<u>\$ —</u>	232
Investment funds ⁽²⁾ measured at net asset value				284
Total assets measured at fair value				\$ 516

(1) Refer to Note 12 for additional discussion regarding the three levels of the fair value hierarchy.

(2) Investment funds are comprised of mutual funds and collective trust funds. These funds consist of equity and debt securities of approximately 71% and 29%, respectively, for 2024 and 68% and 32%, respectively, for 2023. Additionally, these funds are invested in U.S. and international securities of approximately 94% and 6%, respectively, for 2024 and 93% and 7%, respectively, for 2023.

The following table presents the fair value of plan assets, by major category, for MidAmerican Energy's defined benefit other postretirement plans (in millions):

	Input Levels for Fair Value Measurements ⁽¹⁾			
	Level 1	Level 2	Level 3	Total
<u>As of December 31, 2024:</u>				
Cash equivalents	\$ 9	\$ —	\$ —	\$ 9
Debt securities:				
U.S. government obligations	2	—	—	2
Corporate obligations	—	3	—	3
Municipal obligations	—	25	—	25
Agency, asset and mortgage-backed obligations	—	3	—	3
Equity securities:				
Investment funds ⁽²⁾	264	—	—	264
Total assets measured at fair value	<u>\$ 275</u>	<u>\$ 31</u>	<u>\$ —</u>	<u>\$ 306</u>
<u>As of December 31, 2023:</u>				
Cash equivalents	\$ 9	\$ —	\$ —	\$ 9
Debt securities:				
U.S. government obligations	2	—	—	2
Corporate obligations	—	5	—	5
Municipal obligations	—	26	—	26
Agency, asset and mortgage-backed obligations	—	6	—	6
Equity securities:				
Investment funds ⁽²⁾	230	—	—	230
Total assets measured at fair value	<u>\$ 241</u>	<u>\$ 37</u>	<u>\$ —</u>	<u>\$ 278</u>

(1) Refer to Note 12 for additional discussion regarding the three levels of the fair value hierarchy.

(2) Investment funds are comprised of mutual funds and collective trust funds. These funds consist of equity and debt securities of approximately 84% and 16%, respectively, for 2024 and 83% and 17%, respectively, for 2023. Additionally, these funds are invested in U.S. and international securities of approximately 84% and 16%, respectively, for 2024 and 83% and 17%, respectively, for 2023.

For level 1 investments, a readily observable quoted market price or net asset value of an identical security in an active market is used to record the fair value. For level 2 investments, the fair value is determined using pricing models based on observable market inputs. Shares of mutual funds not registered under the Securities Act of 1933, private equity limited partnership interests, common and commingled trust funds and investment entities are reported at fair value based on the net asset value per unit, which is used for expedience purposes. A fund's net asset value is based on the fair value of the underlying assets held by the fund less its liabilities.

Defined Contribution Plan

MidAmerican Energy sponsors a defined contribution plan ("401(k) plan") covering substantially all employees. MidAmerican Energy's matching contributions are based on each participant's level of contribution, and certain participants receive contributions based on eligible pretax annual compensation. Contributions cannot exceed the maximum allowable for tax purposes. Certain participants now receive enhanced benefits in the 401(k) plan and no longer accrue benefits in the noncontributory defined benefit pension plans. MidAmerican Energy's contributions to the plan were \$36 million, \$34 million, and \$33 million for the years ended December 31, 2024, 2023 and 2022, respectively.

(11) Asset Retirement Obligations

MidAmerican Energy estimates its ARO liabilities based upon detailed engineering calculations of the amount and timing of the future cash spending for a third party to perform the required work. Spending estimates are escalated for inflation and then discounted at a credit-adjusted, risk-free rate. Changes in estimates could occur for a number of reasons, including changes in laws and regulations, plan revisions, inflation and changes in the amount and timing of the expected work. The change in estimated costs for 2023 was primarily the result of an updated decommissioning estimate for its wind-powered generating facilities, which is a non-cash investing activity and reflects changes in the projected removal costs per turbine.

MidAmerican Energy does not recognize liabilities for AROs for which the fair value cannot be reasonably estimated. Due to the indeterminate removal date, the fair value of the associated liabilities on certain generation, transmission, distribution and other assets cannot currently be estimated, and no amounts are recognized on the Financial Statements other than those included in the cost of removal regulatory liability established via approved depreciation rates in accordance with accepted regulatory practices. These accruals totaled \$452 million and \$411 million as of December 31, 2024 and 2023, respectively.

The following table presents MidAmerican Energy's ARO liabilities by asset type as of December 31 (in millions):

	2024	2023
Quad Cities Station	\$ 428	\$ 407
Wind-powered generating facilities	318	305
Fossil-fueled generating facilities	79	62
Solar-powered generating facilities and other	4	4
Total asset retirement obligations	<u>\$ 829</u>	<u>\$ 778</u>
Quad Cities Station nuclear decommissioning trust funds ⁽¹⁾	<u>\$ 871</u>	<u>\$ 767</u>

(1) Refer to Note 6 for a discussion of the Quad Cities Station nuclear decommissioning trust funds.

The following table reconciles the beginning and ending balances of MidAmerican Energy's ARO liabilities for the years ended December 31 (in millions):

	2024	2023
Beginning balance	\$ 778	\$ 707
Change in estimated costs	(2)	56
Additions	20	3
Retirements	(1)	(21)
Accretion	34	33
Ending balance	<u>\$ 829</u>	<u>\$ 778</u>
Reflected as:		
Other current liabilities	\$ 6	\$ 10
Asset retirement obligations	823	768
	<u>\$ 829</u>	<u>\$ 778</u>

Retirements in 2024 and 2023 relate to settlements of MidAmerican Energy's coal combustion residuals ARO liabilities.

In May 2024, the United States Environmental Protection Agency published its final rule on legacy coal combustion residuals ("CCR") surface impoundments and CCR management units ("CCRMUs") in the Federal Register. CCRMUs include CCR surface impoundments and landfills closed before October 19, 2015 and inactive CCR landfills. The final rule contains three main components: (1) a definition for legacy CCR surface impoundments, which are inactive surface impoundments at inactive generating facilities that must adhere to the same regulations as inactive CCR impoundments at active generating facilities, barring location restrictions and liner design criteria, with customized compliance deadlines; (2) groundwater monitoring, corrective action, closure, and post closure care requirements for CCRMUs, which may be located at active generating facilities and inactive generating facilities with a legacy CCR surface impoundment; and (3) the owners and operators of inactive generating facilities must identify the presence of legacy CCR surface impoundments and comply with all rule requirements for surface impoundments; and the owners and operators of active generating facilities and inactive generating facilities with a legacy CCR surface impoundment must prepare Facility Evaluation Reports ("FERs") that identify and describe the CCRMUs and determine whether closure is required. In a manner consistent with existing CCR rules, owners and operators must publish FERs on their CCR websites in two parts, within 15 months (Part 1) and 27 months (Part 2) of the final rule's effective date in November 2024. MidAmerican Energy is currently evaluating the final rule and does not anticipate identifying any legacy surface impoundments, but does anticipate identifying CCRMUs subject to the rule. Due to the number of site investigations warranted by this rule and the nature of engineering and other studies required at each site, MidAmerican Energy is unable to reasonably estimate the potential impact, which may be material, to its asset retirement obligations.

(12) Fair Value Measurements

The carrying value of MidAmerican Energy's cash, certain cash equivalents, receivables, payables, accrued liabilities and short-term borrowings approximates fair value because of the short-term maturity of these instruments. MidAmerican Energy has various financial assets and liabilities that are measured at fair value on the Financial Statements using inputs from the three levels of the fair value hierarchy. A financial asset or liability classification within the hierarchy is determined based on the lowest level input that is significant to the fair value measurement. The three levels are as follows:

- Level 1 - Inputs are unadjusted quoted prices in active markets for identical assets or liabilities that MidAmerican Energy has the ability to access at the measurement date.
- Level 2 - Inputs include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived principally from or corroborated by observable market data by correlation or other means (market corroborated inputs).
- Level 3 - Unobservable inputs reflect MidAmerican Energy's judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. MidAmerican Energy develops these inputs based on the best information available, including its own data.

The following table presents MidAmerican Energy's financial assets and liabilities recognized on the Balance Sheets and measured at fair value on a recurring basis (in millions):

	Input Levels for Fair Value Measurements					
	Level 1	Level 2	Level 3	Other ⁽¹⁾	Total	
As of December 31, 2024:						
Assets:						
Commodity derivatives	\$ —	\$ 5	\$ 1	\$ (3)	\$ 3	
Money market mutual funds	538	—	—	—	538	
Debt securities:						
U.S. government obligations	271	—	—	—	271	
Corporate obligations	—	109	—	—	109	
Municipal obligations	—	2	—	—	2	
Equity securities:						
U.S. companies	479	—	—	—	479	
International companies	9	—	—	—	9	
Investment funds	23	—	—	—	23	
	<u>\$ 1,320</u>	<u>\$ 116</u>	<u>\$ 1</u>	<u>\$ (3)</u>	<u>\$ 1,434</u>	
Liabilities - commodity derivatives	<u>\$ —</u>	<u>\$ (15)</u>	<u>\$ (3)</u>	<u>\$ 6</u>	<u>\$ (12)</u>	
As of December 31, 2023:						
Assets:						
Commodity derivatives	\$ —	\$ 15	\$ —	\$ (2)	\$ 13	
Money market mutual funds	643	—	—	—	643	
Debt securities:						
U.S. government obligations	257	—	—	—	257	
Corporate obligations	—	70	—	—	70	
Municipal obligations	—	3	—	—	3	
Equity securities:						
U.S. companies	427	—	—	—	427	
International companies	9	—	—	—	9	
Investment funds	19	—	—	—	19	
	<u>\$ 1,355</u>	<u>\$ 88</u>	<u>\$ —</u>	<u>\$ (2)</u>	<u>\$ 1,441</u>	
Liabilities - commodity derivatives	<u>\$ —</u>	<u>\$ (15)</u>	<u>\$ (11)</u>	<u>\$ 14</u>	<u>\$ (12)</u>	

(1) Represents netting under master netting arrangements and a net cash collateral receivable of \$3 million and \$12 million as of December 31, 2024 and 2023, respectively.

MidAmerican Energy's investments in money market mutual funds and debt and equity securities are stated at fair value, with debt securities accounted for as available-for-sale securities. When available, a readily observable quoted market price or net asset value of an identical security in an active market is used to record the fair value. In the absence of a quoted market price or net asset value of an identical security, the fair value is determined using pricing models or net asset values based on observable market inputs and quoted market prices of securities with similar characteristics.

The following table reconciles the beginning and ending balances of MidAmerican Energy's commodity derivative assets and liabilities measured at fair value on a recurring basis using significant Level 3 inputs (in millions):

	2024	2023	2022
Beginning balance	\$ (11)	\$ 5	\$ (5)
Changes in fair value recognized in net regulatory assets	(13)	(40)	37
Settlements	22	24	(27)
Ending balance	<u>\$ (2)</u>	<u>\$ (11)</u>	<u>\$ 5</u>

MidAmerican Energy's long-term debt is carried at cost on the Financial Statements. The fair value of MidAmerican Energy's long-term debt is a Level 2 fair value measurement and has been estimated based upon quoted market prices, where available, or at the present value of future cash flows discounted at rates consistent with comparable maturities with similar credit risks. The carrying value of MidAmerican Energy's variable-rate long-term debt approximates fair value because of the frequent repricing of these instruments at market rates. The following table presents the carrying value and estimated fair value of MidAmerican Energy's long-term debt as of December 31 (in millions):

	2024		2023	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	<u>\$ 8,824</u>	<u>\$ 7,911</u>	<u>\$ 8,766</u>	<u>\$ 8,252</u>

(13) Commitments and Contingencies

Commitments

MidAmerican Energy had the following firm commitments that are not reflected on the Balance Sheet. Minimum payments as of December 31, 2024, are as follows (in millions):

	2025	2026	2027	2028	2029	2030 and Thereafter	Total
Contract type:							
Coal and natural gas for generation	\$ 83	\$ 47	\$ 37	\$ 6	\$ —	\$ —	\$ 173
Electric capacity and transmission	33	32	17	8	—	—	90
Natural gas contracts for gas operations	219	94	65	25	5	14	422
Construction commitments	402	74	38	24	17	—	555
Easements	45	46	47	48	49	1,650	1,885
Maintenance, services and other	156	153	131	95	77	18	630
	<u>\$ 938</u>	<u>\$ 446</u>	<u>\$ 335</u>	<u>\$ 206</u>	<u>\$ 148</u>	<u>\$ 1,682</u>	<u>\$ 3,755</u>

Coal, Natural Gas, Electric Capacity and Transmission Commitments

MidAmerican Energy has coal supply and related transportation and lime contracts for its coal-fueled generating facilities. MidAmerican Energy expects to supplement the coal contracts with additional contracts and spot market purchases to fulfill its future coal supply needs. Additionally, MidAmerican Energy has a natural gas transportation contract for a natural gas-fueled generating facility. The contracts have minimum payment commitments ranging through 2028.

MidAmerican Energy has various natural gas supply and transportation contracts for its regulated natural gas operations that have minimum payment commitments ranging through 2037.

MidAmerican Energy has contracts to purchase electric capacity that have minimum payment commitments ranging through 2028. MidAmerican Energy also has contracts for the right to transmit electricity over other entities' transmission lines with minimum payment commitments ranging through 2027.

Construction Commitments

MidAmerican Energy's firm construction commitments reflected in the table above consist primarily of contracts for the repowering of wind-powered generating facilities, construction of new generating facilities, and the settlement of AROs.

Easements

MidAmerican Energy has non-cancelable easements with minimum payment commitments ranging through 2061 for land in Iowa on which certain of its assets, primarily wind- and solar-powered generating facilities, are located.

Maintenance, Services and Other Contracts

MidAmerican Energy has other non-cancelable contracts primarily related to maintenance and services for various generating facilities with minimum payment commitments ranging through 2035.

Environmental Laws and Regulations

MidAmerican Energy is subject to federal, state and local laws and regulations regarding air quality, climate change, emissions performance standards, water quality, coal ash disposal and other environmental matters that have the potential to impact its current and future operations. MidAmerican Energy believes it is in material compliance with all applicable laws and regulations.

Legal Matters

MidAmerican Energy is party to a variety of legal actions arising out of the normal course of business. MidAmerican Energy does not believe that such normal and routine litigation will have a material impact on its financial results.

Transmission Rates

MidAmerican Energy's wholesale transmission rates are set annually using formula rates approved by the FERC subject to true-up for actual cost of service. In November 2013 and February 2015, a coalition of intervenors filed successive complaints with the FERC requesting that the base return on equity ("ROE") used to determine rates in effect prior to September 2016 no longer be found just and reasonable and sought to reduce the base ROE. In August 2022, the U.S. Court of Appeals for the District of Columbia Circuit issued an opinion vacating all orders related to the complaints and remanding them back to the FERC. In October 2024, the FERC issued an order addressing the remand. The order sets a just and reasonable ROE for the first complaint period and for the period from September 28, 2016, forward. The order continued to find that no refunds are required for the second complaint period. MidAmerican Energy has evaluated the impact of the order and has determined it will not have a material impact on its financial results.

(14) Revenue from Contracts with Customers

MidAmerican Energy uses a single five-step model to identify and recognize Customer Revenue upon transfer of control of promised goods or services to customers in an amount that reflects the consideration to which it expects to be entitled in exchange for those goods or services. The following table summarizes MidAmerican Energy's revenue by line of business and customer class, including a reconciliation to MidAmerican Energy's reportable segment information included in Note 19, (in millions):

For the Year Ended December 31, 2024				
	Electric	Natural Gas	Other	Total
Customer Revenue:				
Retail:				
Residential	\$ 729	\$ 392	\$ —	\$ 1,121
Commercial	333	138	—	471
Industrial	1,069	17	—	1,086
Natural gas transportation services	—	51	—	51
Other retail	156	6	—	162
Total retail	2,287	604	—	2,891
Wholesale	168	53	—	221
Multi-value transmission projects	53	—	—	53
Other Customer Revenue	—	—	9	9
Total Customer Revenue	2,508	657	9	3,174
Other revenue	76	1	—	77
Total operating revenue	\$ 2,584	\$ 658	\$ 9	\$ 3,251

For the Year Ended December 31, 2023				
	Electric	Natural Gas	Other	Total
Customer Revenue:				
Retail:				
Residential	\$ 735	\$ 420	\$ —	\$ 1,155
Commercial	344	152	—	496
Industrial	1,075	20	—	1,095
Natural gas transportation services	—	46	—	46
Other retail	155	—	—	155
Total retail	2,309	638	—	2,947
Wholesale	230	73	—	303
Multi-value transmission projects	54	—	—	54
Other Customer Revenue	—	—	7	7
Total Customer Revenue	2,593	711	7	3,311
Other revenue	80	2	—	82
Total operating revenue	\$ 2,673	\$ 713	\$ 7	\$ 3,393

For the Year Ended December 31, 2022				
	Electric	Natural Gas	Other	Total
Customer Revenue:				
Retail:				
Residential	\$ 765	\$ 555	\$ —	\$ 1,320
Commercial	354	216	—	570
Industrial	1,047	38	—	1,085
Natural gas transportation services	—	44	—	44
Other retail	154	2	—	156
Total retail	2,320	855	—	3,175
Wholesale	495	173	—	668
Multi-value transmission projects	61	—	—	61
Other Customer Revenue	—	—	7	7
Total Customer Revenue	2,876	1,028	7	3,911
Other revenue	112	2	—	114
Total operating revenue	\$ 2,988	\$ 1,030	\$ 7	\$ 4,025

(15) Shareholder's Equity

In 2024 and 2023, MidAmerican Energy paid \$425 million and \$1,025 million, respectively, in cash dividends to its parent company, MHC.

(16) Other Income (Expense)

Other, net, as shown on the Statements of Operations, includes the following other income (expense) items for the years ended December 31 (in millions):

	2024	2023	2022
Corporate-owned life insurance income (loss)	\$ 29	\$ 23	\$ (16)
Non-service cost components of postretirement employee benefit plans	8	8	9
Interest income and other, net	46	5	7
Total	\$ 83	\$ 36	\$ —

(17) Supplemental Cash Flow Disclosures

The summary of supplemental cash flow disclosures as of and for the years ending December 31 is as follows (in millions):

	2024	2023	2022
Supplemental disclosure of cash flow information:			
Interest paid, net of amounts capitalized	\$ 374	\$ 300	\$ 292
Income taxes received, net	\$ 898	\$ 852	\$ 840
Supplemental disclosure of non-cash investing transactions:			
Accruals related to property, plant and equipment additions	\$ 108	\$ 193	\$ 168

(18) Related Party Transactions

The companies identified as affiliates of MidAmerican Energy are Berkshire Hathaway and its subsidiaries, including BHE and its subsidiaries. The basis for the following transactions is provided for in service agreements between MidAmerican Energy and the affiliates.

MidAmerican Energy is reimbursed for charges incurred on behalf of its affiliates. The majority of these reimbursed expenses are for general costs, such as insurance and building rent, and for employee wages, benefits and costs related to corporate functions such as information technology, human resources, treasury, legal and accounting. The amount of such reimbursements was \$88 million, \$94 million and \$78 million for 2024, 2023 and 2022, respectively.

MidAmerican Energy reimbursed BHE in the amount of \$124 million, \$123 million and \$79 million in 2024, 2023 and 2022, respectively, for its share of technology costs, corporate expenses and other costs. Amounts charged to MidAmerican Energy in 2024 and 2023 were primarily reflected in construction work-in-progress on the Balance Sheets as of December 31, 2024 and 2023.

MidAmerican Energy purchases, in the normal course of business at either tariffed or market prices, natural gas transportation and storage capacity services from Northern Natural Gas Company, a wholly owned subsidiary of BHE, and coal transportation services from BNSF Railway Company, an indirect wholly owned subsidiary of Berkshire Hathaway. These purchases totaled \$133 million, \$141 million and \$141 million in 2024, 2023 and 2022, respectively.

MidAmerican Energy had accounts receivable from affiliates of \$19 million and \$9 million as of December 31, 2024 and 2023, respectively, that are included in other current assets on the Balance Sheets. MidAmerican Energy also had accounts payable to affiliates of \$16 million and \$32 million as of December 31, 2024 and 2023, respectively, that are included in accounts payable on the Balance Sheets.

MidAmerican Energy is party to a tax-sharing agreement and is part of the Berkshire Hathaway consolidated U.S. federal income tax return. For current federal and state income taxes, MidAmerican Energy had a net receivable from BHE of \$1 million and a net payable to BHE of \$21 million as of December 31, 2024 and 2023, respectively. MidAmerican Energy received net cash payments for federal and state income taxes from BHE totaling \$898 million, \$852 million and \$840 million for the years ended December 31, 2024, 2023 and 2022, respectively.

MidAmerican Energy recognizes the full amount of the funded status for its pension and postretirement plans, and amounts attributable to MidAmerican Energy's affiliates that have not previously been recognized through income are recognized as an intercompany balance with such affiliates. MidAmerican Energy adjusts these balances when changes to the funded status of the respective plans are recognized and does not intend to settle the balances currently. Amounts receivable from affiliates attributable to the funded status of employee benefit plans totaled \$70 million and \$82 million as of December 31, 2024 and 2023, respectively, and are included in other assets on the Balance Sheets. Similar amounts payable to affiliates totaled \$69 million and \$55 million as of December 31, 2024 and 2023, respectively, and are included in other long-term liabilities on the Balance Sheets. See Note 10 for further information pertaining to pension and postretirement accounting.

(19) Segment Information

MidAmerican Energy's chief operating decision maker ("CODM") is its President and Chief Executive Officer. Net income for each reportable segment is considered by the CODM in allocating resources and capital. The CODM generally considers actual results versus historical results, budgets or forecasts, as well as unique risks and opportunities, when making decisions about the allocation of resources and capital to each reportable segment.

MidAmerican Energy has identified two reportable operating segments: regulated electric and regulated natural gas. The regulated electric segment derives most of its revenue from regulated retail sales of electricity to residential, commercial, and industrial customers and from wholesale sales. The regulated natural gas segment derives most of its revenue from regulated retail sales of natural gas to residential, commercial, and industrial customers and also obtains revenue by transporting natural gas owned by others through its distribution system. Pricing for regulated electric and regulated natural gas sales are established separately by regulatory agencies; therefore, management also reviews each segment separately to make decisions regarding allocation of resources and in evaluating performance. Common operating costs are allocated to each segment based on certain factors, which primarily relate to the nature of the cost.

The following tables provide information on a reportable segment basis for the year ended December 31 (in millions):

	2024			
	Electric	Natural Gas	Other ⁽¹⁾	Total
Operating revenue	\$ 2,584	\$ 658	\$ 9	\$ 3,251
Cost of sales	430	367	—	797
Operations and maintenance	757	121	1	879
Depreciation and amortization	935	66	—	1,001
Property and other taxes	152	14	—	166
Operating income	310	90	8	408
Interest expense	(387)	(30)	—	(417)
Interest and dividend income	37	3	—	40
Income tax expense (benefit)	(841)	(1)	3	(839)
Other segment items ⁽²⁾	129	7	(3)	133
Net income	<u>\$ 930</u>	<u>\$ 71</u>	<u>\$ 2</u>	<u>\$ 1,003</u>
Capital expenditures	<u>\$ 1,580</u>	<u>\$ 114</u>	<u>\$ 10</u>	<u>\$ 1,704</u>
Total assets	<u>\$ 24,159</u>	<u>\$ 1,956</u>	<u>\$ 1</u>	<u>\$ 26,116</u>
	2023			
	Electric	Natural Gas	Other ⁽¹⁾	Total
Operating revenue	\$ 2,673	\$ 713	\$ 7	\$ 3,393
Cost of sales	501	451	—	952
Operations and maintenance	711	138	2	851
Depreciation and amortization	846	62	—	908
Property and other taxes	144	17	—	161
Operating income	471	45	5	521
Interest expense	(320)	(26)	—	(346)
Interest and dividend income	22	2	—	24
Income tax expense (benefit)	(676)	(14)	(3)	(693)
Other segment items ⁽²⁾	80	15	(5)	90
Net income	<u>\$ 929</u>	<u>\$ 50</u>	<u>\$ 3</u>	<u>\$ 982</u>
Capital expenditures	<u>\$ 1,683</u>	<u>\$ 149</u>	<u>\$ 1</u>	<u>\$ 1,833</u>
Total assets	<u>\$ 23,334</u>	<u>\$ 1,900</u>	<u>\$ 1</u>	<u>\$ 25,235</u>

	2022			
	Electric	Natural Gas	Other ⁽¹⁾	Total
Operating revenue	\$ 2,988	\$ 1,030	\$ 7	\$ 4,025
Cost of sales	679	762	1	1,442
Operations and maintenance	692	135	1	828
Depreciation and amortization	1,112	56	—	1,168
Property and other taxes	133	16	—	149
Operating income	372	61	5	438
Interest expense	(290)	(23)	—	(313)
Interest and dividend income	6	1	—	7
Income tax expense (benefit)	(779)	9	—	(770)
Other segment items ⁽²⁾	64	—	(5)	59
Net income	<u>\$ 931</u>	<u>\$ 30</u>	<u>\$ —</u>	<u>\$ 961</u>
Capital expenditures	<u>\$ 1,742</u>	<u>\$ 127</u>	<u>\$ —</u>	<u>\$ 1,869</u>
Total assets	<u>\$ 22,092</u>	<u>\$ 1,885</u>	<u>\$ 1</u>	<u>\$ 23,978</u>

(1) The differences between the reportable segment amounts and the consolidated amounts, described as Other, relate to nonregulated activities of the Company.

(2) Other segment items include allowance for borrowed and equity funds, gains (losses) on marketable securities and other income (expense).

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Managers and Member of
MidAmerican Funding, LLC
Des Moines, Iowa

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of MidAmerican Funding, LLC and subsidiaries ("MidAmerican Funding") as of December 31, 2024 and 2023, the related consolidated statements of operations, changes in member's equity, and cash flows for each of the three years in the period ended December 31, 2024, the related notes and the schedule listed in the Index at Item 15(a)(2) (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of MidAmerican Funding as of December 31, 2024 and 2023, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2024, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of MidAmerican Funding's management. Our responsibility is to express an opinion on MidAmerican Funding's financial statements 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 MidAmerican Funding 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 and in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. MidAmerican Funding is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of MidAmerican Funding's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the 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 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 financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the executive committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the 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.

Regulatory Matters — Effects of Rate Regulation on the Financial Statements — Refer to Note 5 to the financial statements

Critical Audit Matter Description

MidAmerican Funding is subject to rate regulation by state public service commissions as well as the Federal Energy Regulatory Commission (collectively, the "Commissions"), which have jurisdiction with respect to the rates of electric and natural gas companies in the respective service territories where MidAmerican Funding operates. Management has determined its regulated operations meet the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the specialized rules to account for the effects of cost-based rate regulation. Accounting for the economic effects of rate regulation has a pervasive effect on the financial statements.

Regulated rates are subject to regulatory rate-setting processes. Rates are determined, approved, and established based on a cost-of-service basis, which is designed to allow MidAmerican Funding an opportunity to recover its prudently incurred costs of providing services and to earn a reasonable return on its invested capital. Regulatory decisions can have an effect on the recovery of costs, the rate of return earned on investment, and the timing and amount of assets to be recovered by rates. While MidAmerican Funding has indicated it expects to recover costs from customers through regulated rates, there is a risk that changes to the Commissions' approach to setting rates or other regulatory actions could limit MidAmerican Funding's ability to recover its costs.

We identified the effects of rate regulation on the financial statements as a critical audit matter due to the significant judgments made by management to support its assertions about affected account balances and disclosures and the high degree of subjectivity involved in assessing the impact of regulatory orders on the financial statements. Management judgments include assessing the likelihood of (1) recovery in future rates of incurred costs, (2) a disallowance of part of the cost of recently completed plant or plant under construction, and (3) a refund to customers. Given that management's accounting judgments are based on assumptions about the outcome of decisions by the Commissions, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate setting process due to its inherent complexities.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the uncertainty of decisions by the Commissions included the following, among others:

- We evaluated MidAmerican Funding's disclosures related to the effects of rate regulation by testing recorded balances and evaluating regulatory developments.
- We read relevant regulatory orders issued by the Commissions, regulatory statutes, filings made by MidAmerican Funding and intervenors, and other external information. We evaluated relevant external information and compared it to certain recorded regulatory asset and liability balances for completeness.
- For certain regulatory matters, we inspected MidAmerican Funding's filings with the Commissions and the filings with the Commissions by intervenors to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedents of the Commissions' treatment of similar costs under similar circumstances.
- We inquired of management about property, plant, and equipment that may be abandoned. We inquired of management to identify projects that are designed to replace assets that may be retired prior to the end of the useful life. We inspected minutes of the board of directors and regulatory orders and other filings with the Commissions to identify any evidence that may contradict management's assertion regarding probability of an abandonment.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
February 21, 2025

We have served as MidAmerican Funding's auditor since 1999.

MIDAMERICAN FUNDING, LLC AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Amounts in millions)

	As of December 31,	
	2024	2023
ASSETS		
Current assets:		
Cash and cash equivalents	\$ 552	\$ 637
Trade receivables, net	230	272
Income tax receivable	2	1
Inventories	369	364
Prepayments	117	113
Other current assets	62	40
Total current assets	1,332	1,427
Property, plant and equipment, net	22,766	21,971
Goodwill	1,270	1,270
Regulatory assets	622	600
Investments and restricted investments	1,149	1,032
Other assets	251	209
Total assets	\$ 27,390	\$ 26,509

The accompanying notes are an integral part of these consolidated financial statements.

MIDAMERICAN FUNDING, LLC AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (continued)
(Amounts in millions)

	As of December 31,	
	2024	2023
LIABILITIES AND MEMBER'S EQUITY		
Current liabilities:		
Accounts payable	\$ 375	\$ 543
Accrued interest	122	112
Accrued property, income and other taxes	192	197
Note payable to affiliate	13	—
Current portion of long-term debt	17	539
Other current liabilities	92	102
Total current liabilities	811	1,493
Long-term debt	9,047	8,467
Regulatory liabilities	1,264	1,079
Deferred income taxes	3,624	3,492
Asset retirement obligations	823	768
Other long-term liabilities	622	577
Total liabilities	16,191	15,876
Commitments and contingencies (Note 13)		
Member's equity:		
Paid-in capital	1,679	1,679
Retained earnings	9,520	8,954
Total member's equity	11,199	10,633
Total liabilities and member's equity	\$ 27,390	\$ 26,509

The accompanying notes are an integral part of these consolidated financial statements.

MIDAMERICAN FUNDING, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2024	2023	2022
Operating revenue:			
Regulated electric	\$ 2,584	\$ 2,673	\$ 2,988
Regulated natural gas and other	667	720	1,037
Total operating revenue	3,251	3,393	4,025
Operating expenses:			
Cost of fuel and energy	430	501	679
Cost of natural gas purchased for resale and other	367	451	763
Operations and maintenance	879	851	828
Depreciation and amortization	1,001	908	1,168
Property and other taxes	166	161	149
Total operating expenses	2,843	2,872	3,587
Operating income	408	521	438
Other income (expense):			
Interest expense	(434)	(362)	(333)
Allowance for borrowed funds	25	19	15
Allowance for equity funds	65	59	51
Other, net	84	48	—
Total other income (expense)	(260)	(236)	(267)
Income before income tax expense (benefit)	148	285	171
Income tax expense (benefit)	(843)	(695)	(776)
Net income	\$ 991	\$ 980	\$ 947

The accompanying notes are an integral part of these consolidated financial statements.

MIDAMERICAN FUNDING, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN MEMBER'S EQUITY
(Amounts in millions)

	<u>Paid-in Capital</u>	<u>Retained Earnings</u>	<u>Total Member's Equity</u>
Balance, December 31, 2021	\$ 1,679	\$ 8,122	\$ 9,801
Net income	—	947	947
Distribution to member	—	(69)	(69)
Balance, December 31, 2022	1,679	9,000	10,679
Net income	—	980	980
Distributions to member	—	(1,025)	(1,025)
Other equity transactions	—	(1)	(1)
Balance, December 31, 2023	1,679	8,954	10,633
Net income	—	991	991
Distribution to member	—	(425)	(425)
Other equity transactions	—	—	—
Balance, December 31, 2024	<u>\$ 1,679</u>	<u>\$ 9,520</u>	<u>\$ 11,199</u>

The accompanying notes are an integral part of these consolidated financial statements.

MIDAMERICAN FUNDING, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Amounts in millions)

	Years Ended December 31,		
	2024	2023	2022
Cash flows from operating activities:			
Net income	\$ 991	\$ 980	\$ 947
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	1,001	908	1,168
Amortization of utility plant to other operating expenses	35	34	35
Allowance for equity funds	(65)	(59)	(51)
Deferred income taxes and amortization of investment tax credits	81	90	33
Settlements of asset retirement obligations	(1)	(21)	(85)
Other, net	20	33	52
Changes in other operating assets and liabilities:			
Trade receivables and other assets	16	254	(11)
Inventories	(5)	(87)	(43)
Pension and other postretirement benefit plans, net	2	3	8
Accrued property, income and other taxes, net	(18)	77	40
Accounts payable and other liabilities	(90)	(9)	68
Net cash flows from operating activities	<u>1,967</u>	<u>2,203</u>	<u>2,161</u>
Cash flows from investing activities:			
Capital expenditures	(1,704)	(1,833)	(1,869)
Purchases of marketable securities	(327)	(243)	(499)
Proceeds from sales of marketable securities	313	227	492
Other investment proceeds	12	12	2
Other, net	15	12	6
Net cash flows from investing activities	<u>(1,691)</u>	<u>(1,825)</u>	<u>(1,868)</u>
Cash flows from financing activities:			
Distributions to member	(425)	(1,025)	(69)
Proceeds from long-term debt	592	1,338	—
Repayments of long-term debt	(539)	(317)	(2)
Net change in note payable to affiliate	13	—	(189)
Other, net	(2)	(2)	(2)
Net cash flows from financing activities	<u>(361)</u>	<u>(6)</u>	<u>(262)</u>
Net change in cash and cash equivalents and restricted cash and cash equivalents	(85)	372	31
Cash and cash equivalents and restricted cash and cash equivalents at beginning of year	643	271	240
Cash and cash equivalents and restricted cash and cash equivalents at end of year	<u>\$ 558</u>	<u>\$ 643</u>	<u>\$ 271</u>

The accompanying notes are an integral part of these consolidated financial statements.

MIDAMERICAN FUNDING, LLC AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Organization and Operations

MidAmerican Funding, LLC ("MidAmerican Funding") is an Iowa limited liability company with Berkshire Hathaway Energy Company ("BHE") as its sole member. BHE is a holding company based in Des Moines, Iowa that has investments in subsidiaries principally engaged in energy businesses. BHE is a wholly owned subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway"). MidAmerican Funding's direct wholly owned subsidiary is MHC Inc. ("MHC"), which constitutes substantially all of MidAmerican Funding's assets, liabilities and business activities except those related to MidAmerican Funding's long-term debt securities. MHC conducts no business other than the ownership of its subsidiaries. MHC's principal subsidiary is MidAmerican Energy Company ("MidAmerican Energy"), a public utility with electric and natural gas operations, and its direct, wholly owned nonregulated subsidiary is Midwest Capital Group, Inc. ("Midwest Capital Group").

(2) Summary of Significant Accounting Policies

In addition to the following significant accounting policies, refer to Note 2 of MidAmerican Energy's Notes to Financial Statements for significant accounting policies of MidAmerican Funding.

Basis of Consolidation and Presentation

The Consolidated Financial Statements include the accounts of MidAmerican Funding and its subsidiaries in which it held a controlling financial interest as of the financial statement date. Intercompany accounts and transactions have been eliminated, other than those between rate-regulated operations. The Consolidated Statements of Comprehensive Income have been omitted as net income equals comprehensive income for the years ended December 31, 2024, 2023 and 2022.

Cash and Cash Equivalents and Restricted Cash and Cash Equivalents

Cash equivalents consist of funds invested in money market mutual funds, U.S. Treasury Bills and other investments with a maturity of three months or less when purchased. Cash and cash equivalents exclude amounts where availability is restricted by legal requirements, loan agreements or other contractual provisions. Restricted cash and cash equivalents consist substantially of funds restricted for wildlife preservation. A reconciliation of cash and cash equivalents and restricted cash and cash equivalents as of December 31, 2024 and 2023 as presented on the Consolidated Statements of Cash Flows is outlined below and disaggregated by the line items in which they appear on the Consolidated Balance Sheets (in millions):

	As of December 31,	
	2024	2023
Cash and cash equivalents	\$ 552	\$ 637
Restricted cash and cash equivalents in other current assets	6	6
Total cash and cash equivalents and restricted cash and cash equivalents	<u>\$ 558</u>	<u>\$ 643</u>

Goodwill

Goodwill represents the excess of the purchase price over the fair value of identifiable net assets acquired when MidAmerican Funding purchased MHC. MidAmerican Funding evaluates goodwill for impairment at least annually and completed its annual review as of October 31, 2024. When evaluating goodwill for impairment, MidAmerican Funding estimates the fair value of its reporting units. If the carrying amount of a reporting unit, including goodwill, exceeds the estimated fair value, then the identifiable assets, including identifiable intangible assets, and liabilities of the reporting unit are estimated at fair value as of the current testing date. The excess of the estimated fair value of the reporting unit over the current estimated fair value of net assets establishes the implied value of goodwill. The excess of the recorded goodwill over the implied goodwill value is charged to earnings as an impairment loss. Significant judgment is required in estimating the fair value of the reporting unit and performing goodwill impairment tests. The determination of fair value incorporates significant unobservable inputs. During 2024, 2023 and 2022, MidAmerican Funding did not record any goodwill impairments.

In November 2023, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2023-07, Segment Reporting Topic 280, "Segment Reporting—Improvements to Reportable Segment Disclosures" which allows disclosure of one or more measures of segment profit or loss used by the chief operating decision maker to allocate resources and assess performance. Additionally, the standard requires enhanced disclosures of significant segment expenses and other segment items as well as incremental qualitative disclosures on both an annual and interim basis. This guidance is effective for annual reporting periods beginning after December 15, 2023, and interim reporting periods after December 15, 2024. Early adoption is permitted and retrospective application is required for all periods presented. MidAmerican Funding adopted this guidance for the fiscal year beginning January 1, 2024 under the retrospective method. The adoption did not have a material impact on MidAmerican Funding's Consolidated Financial Statements but did increase the disclosures included within Notes to Financial Statements. Refer to Note 19 for additional disclosures of certain significant segment expenses.

In December 2023, the FASB issued ASU No. 2023-09, Income Taxes Topic 740, "Income Tax—Improvements to Income Tax Disclosures" which requires enhanced disclosures, including specific categories and disaggregation of information in the effective tax rate reconciliation, disaggregated information related to income taxes paid, income or loss from continuing operations before income tax expense or benefit, and income tax expense or benefit from continuing operations. This guidance is effective for annual reporting periods beginning after December 15, 2024. Early adoption is permitted and should be applied on a prospective basis, however retrospective application is permitted. MidAmerican Funding is currently evaluating the impact of adopting this guidance on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

In November 2024, the FASB issued ASU No. 2024-03, Income Statement—Reporting Comprehensive Income—Expense Disaggregation Disclosures Subtopic 220-40, "Disaggregation of Income Statement Expenses" which addresses requests from investors for more detailed information about certain expenses and requires disclosure of the amounts of purchases of inventory, employee compensation, depreciation and intangible asset amortization included in each relevant expense caption presented on the income statement. This guidance is effective for annual reporting periods beginning after December 15, 2026 and interim reporting periods beginning after December 15, 2027. Early adoption is permitted and should be applied on a prospective basis, however retrospective application is permitted. MidAmerican Funding is currently evaluating the impact of adopting this guidance on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

(3) Property, Plant and Equipment, Net

Refer to Note 3 of MidAmerican Energy's Notes to Financial Statements. In addition to MidAmerican Energy's property, plant and equipment, net, MidAmerican Funding had nonregulated property gross of \$1 million and \$1 million as of December 31, 2024 and 2023, respectively.

(4) Jointly Owned Utility Facilities

Refer to Note 4 of MidAmerican Energy's Notes to Financial Statements.

(5) Regulatory Matters

Refer to Note 5 of MidAmerican Energy's Notes to Financial Statements.

(6) Investments and Restricted Investments

Refer to Note 6 of MidAmerican Energy's Notes to Financial Statements. In addition to MidAmerican Energy's investments and restricted investments, MHC had corporate-owned life insurance policies in a Rabbi trust owned by MHC with a total cash surrender value of \$2 million as of December 31, 2024 and 2023.

(7) Short-term Debt and Credit Facilities

Refer to Note 7 of MidAmerican Energy's Notes to Financial Statements. In addition to MidAmerican Energy's credit facilities, MHC has a \$4 million unsecured credit facility, which expires in June 2025 and has a variable interest rate based on the Secured Overnight Financing Rate, plus a spread. As of December 31, 2024 and 2023, there were no borrowings outstanding under this credit facility. As of December 31, 2024, MHC was in compliance with the covenants of its credit facility.

(8) Long-term Debt

Refer to Note 8 of MidAmerican Energy's Notes to Financial Statements for detail and a discussion of its long-term debt. In addition to MidAmerican Energy's annual repayments of long-term debt, MidAmerican Funding parent company has \$239 million of 6.927% Senior Bonds due in 2029, with a carrying value of \$240 million as of December 31, 2024 and 2023.

The MidAmerican Funding parent company bonds are the direct senior secured obligations of MidAmerican Funding and effectively rank junior to all indebtedness and other liabilities of the direct and indirect subsidiaries of MidAmerican Funding, to the extent of the assets of these subsidiaries. MidAmerican Funding may redeem the bonds in whole or in part at any time at a redemption price equal to the sum of any accrued and unpaid interest to the date of redemption and the greater of (1) 100% of the principal amount of the bonds or (2) the sum of the present values of the remaining scheduled payments of principal and interest on the bonds, discounted to the date of redemption on a semiannual basis at the treasury yield plus 25 basis points.

MidAmerican Funding parent company long-term debt is secured by a pledge of the common stock of MHC, which is not publicly traded. In the event of any triggering event under the related debt indenture, the common stock of MHC would be available to satisfy the applicable debt obligations. Triggering events include, among other specified circumstances, (1) default on the payment of interest for 30 days or principal for three days; (2) a material default in the performance of any material covenants or obligations in the indenture continuing for a period of 90 days after written notice in accordance with the indenture; or (3) the failure generally of MidAmerican Funding or any significant subsidiary to pay its debts when due.

Subsidiaries of MidAmerican Funding must make payments on their own indebtedness before making distributions to MidAmerican Funding. Refer to Note 8 of MidAmerican Energy's Notes to Financial Statements for a discussion of utility regulatory restrictions affecting distributions from MidAmerican Energy. As a result of the utility regulatory restrictions agreed to by MidAmerican Energy in March 1999, MidAmerican Funding had restricted net assets of \$6 billion as of December 31, 2024.

As of December 31, 2024, MidAmerican Funding was in compliance with all of its applicable long-term debt covenants.

Each of MidAmerican Funding's direct or indirect subsidiaries is organized as a legal entity separate and apart from MidAmerican Funding and its other subsidiaries. It should not be assumed that any asset of any subsidiary of MidAmerican Funding will be available to satisfy the obligations of MidAmerican Funding or any of its other subsidiaries; provided, however, that unrestricted cash or other assets which are available for distribution may, subject to applicable law and the terms of financing arrangements of such parties, be advanced, loaned, paid as dividends or otherwise distributed or contributed to MidAmerican Funding, one of its subsidiaries or affiliates thereof.

(9) Income Taxes

MidAmerican Funding's income tax expense (benefit) consists of the following for the years ended December 31 (in millions):

	2024	2023	2022
Current:			
Federal	\$ (888)	\$ (756)	\$ (773)
State	(36)	(29)	(36)
	<u>(924)</u>	<u>(785)</u>	<u>(809)</u>
Deferred:			
Federal	80	109	77
State	2	(18)	(43)
	<u>82</u>	<u>91</u>	<u>34</u>
Investment tax credits	<u>(1)</u>	<u>(1)</u>	<u>(1)</u>
Total	<u>\$ (843)</u>	<u>\$ (695)</u>	<u>\$ (776)</u>

A reconciliation of the federal statutory income tax rate to MidAmerican Funding's effective income tax rate applicable to income before income tax expense (benefit) is as follows for the years ended December 31:

	2024	2023	2022
Federal statutory income tax rate	21 %	21 %	21 %
Income tax credits	(548)	(239)	(416)
State income tax, net of federal income tax impacts	(18)	(13)	(36)
Effects of ratemaking	(22)	(12)	(26)
Other, net	(3)	(1)	3
Effective income tax rate	<u>(570)%</u>	<u>(244)%</u>	<u>(454)%</u>

Income tax credits relate primarily to production tax credits ("PTC") earned by MidAmerican Energy's wind- and solar-powered generating facilities. Federal renewable electricity PTCs are earned as energy from qualifying wind- and solar-powered generating facilities is produced and sold and are based on a per-kilowatt hour rate pursuant to the applicable federal income tax law. Wind- and solar-powered generating facilities are eligible for the credits for 10 years from the date the qualifying generating facilities are placed in-service. PTCs recognized for the years ended December 31, 2024, 2023 and 2022 totaled \$810 million, \$681 million and \$710 million, respectively.

MidAmerican Funding's net deferred income tax liability consists of the following as of December 31 (in millions):

	2024	2023
Deferred income tax assets:		
Regulatory liabilities	\$ 249	\$ 218
Asset retirement obligations	216	204
State carryforwards	66	68
Revenue sharing	47	34
Employee benefits	10	25
Other	81	69
Total deferred income tax assets	<u>669</u>	<u>618</u>
Valuation allowances	<u>(2)</u>	<u>(2)</u>
Total deferred income tax assets, net	<u>667</u>	<u>616</u>
Deferred income tax liabilities:		
Property-related items	(4,154)	(3,972)
Regulatory assets	(134)	(134)
Other	(3)	(2)
Total deferred income tax liabilities	<u>(4,291)</u>	<u>(4,108)</u>
Net deferred income tax liability	<u>\$ (3,624)</u>	<u>\$ (3,492)</u>

As of December 31, 2024, MidAmerican Funding's state tax carryforwards, principally related to \$981 million of net operating losses, expire at various intervals between 2025 and 2046.

The U.S. Internal Revenue Service has closed or effectively settled its examination of MidAmerican Funding's income tax returns through December 31, 2013. The statute of limitations for MidAmerican Funding's income tax returns have expired for certain states through December 31, 2011, and for other states through December 31, 2020, except for the impact of any federal audit adjustments. The closure of examinations, or the expiration of the statute of limitations, for state filings may not preclude the state from adjusting the state net operating loss carryforward utilized in a year for which the statute of limitations is not closed.

A reconciliation of the beginning and ending balances of MidAmerican Funding's net unrecognized tax benefits is as follows for the years ended December 31 (in millions):

	<u>2024</u>	<u>2023</u>
Beginning balance	\$ 22	\$ 16
Additions based on tax positions related to the current year	5	10
Interest	2	1
Reductions based on tax positions related to the current year	(7)	(5)
Ending balance	<u>\$ 22</u>	<u>\$ 22</u>

As of December 31, 2024, MidAmerican Funding had unrecognized tax benefits totaling \$52 million that, if recognized, would have an impact on the effective tax rate. The remaining unrecognized tax benefits relate to tax positions for which ultimate deductibility is highly certain but for which there is uncertainty as to the timing of such deductibility. Recognition of these tax benefits, other than applicable interest and penalties, would not affect MidAmerican Funding's effective income tax rate.

(10) Employee Benefit Plans

Refer to Note 10 of MidAmerican Energy's Notes to Financial Statements for additional information regarding MidAmerican Funding's pension, supplemental retirement and postretirement benefit plans.

Pension and postretirement costs allocated by MidAmerican Funding to its parent and other affiliates in each of the years ended December 31, were as follows (in millions):

	<u>2024</u>	<u>2023</u>	<u>2022</u>
Pension costs	\$ 11	\$ 14	\$ 8
Other postretirement costs	2	2	1

(11) Asset Retirement Obligations

Refer to Note 11 of MidAmerican Energy's Notes to Financial Statements.

(12) Fair Value Measurements

Refer to Note 12 of MidAmerican Energy's Notes to Financial Statements.

MidAmerican Funding's long-term debt is carried at cost on the Consolidated Financial Statements. The fair value of MidAmerican Funding's long-term debt is a Level 2 fair value measurement and has been estimated based upon quoted market prices, where available, or at the present value of future cash flows discounted at rates consistent with comparable maturities with similar credit risks. The carrying value of MidAmerican Funding's variable-rate long-term debt approximates fair value because of the frequent repricing of these instruments at market rates. The following table presents the carrying value and estimated fair value of MidAmerican Funding's long-term debt as of December 31 (in millions):

	<u>2024</u>		<u>2023</u>	
	<u>Carrying Value</u>	<u>Fair Value</u>	<u>Carrying Value</u>	<u>Fair Value</u>
Long-term debt	<u>\$ 9,064</u>	<u>\$ 8,166</u>	<u>\$ 9,006</u>	<u>\$ 8,515</u>

(13) Commitments and Contingencies

Refer to Note 13 of MidAmerican Energy's Notes to Financial Statements.

Legal Matters

MidAmerican Funding is party to a variety of legal actions arising out of the normal course of business. MidAmerican Funding does not believe that such normal and routine litigation will have a material impact on its consolidated financial results.

(14) Revenue from Contracts with Customers

Refer to Note 14 of MidAmerican Energy's Notes to Financial Statements.

(15) Member's Equity

In 2024 and 2023, MidAmerican Funding paid \$425 million and \$1,025 million, respectively, in cash distributions to its parent company, BHE.

(16) Other Income (Expense)

Other, net, as shown on the Consolidated Statements of Operations, includes the following other income (expense) items for the years ended December 31 (in millions):

	2024	2023	2022
Corporate-owned life insurance income (loss)	\$ 29	\$ 23	\$ (16)
Gains on sales of assets and other investments	—	12	—
Non-service cost components of postretirement employee benefit plans	8	8	9
Interest income and other, net	47	5	7
Total	<u>\$ 84</u>	<u>\$ 48</u>	<u>\$ —</u>

(17) Supplemental Cash Flow Information

The summary of supplemental cash flow information as of and for the years ending December 31 is as follows (in millions):

	2024	2023	2022
Supplemental disclosure of cash flow information:			
Interest paid, net of amounts capitalized	<u>\$ 391</u>	<u>\$ 317</u>	<u>\$ 309</u>
Income taxes received, net	<u>\$ 903</u>	<u>\$ 855</u>	<u>\$ 845</u>
Supplemental disclosure of non-cash investing and financing transactions:			
Accruals related to property, plant and equipment additions	<u>\$ 108</u>	<u>\$ 193</u>	<u>\$ 168</u>

(18) Related Party Transactions

The companies identified as affiliates of MidAmerican Funding are Berkshire Hathaway and its subsidiaries, including BHE and its subsidiaries. The basis for the following transactions is provided for in-service agreements between MidAmerican Funding and the affiliates.

MidAmerican Funding is reimbursed for charges incurred on behalf of its affiliates. The majority of these reimbursed expenses are for allocated general costs, such as insurance and building rent, and for employee wages, benefits and costs for corporate functions, such as information technology, human resources, treasury, legal and accounting. The amount of such reimbursements was \$88 million, \$94 million and \$77 million for 2024, 2023 and 2022, respectively.

MidAmerican Funding reimbursed BHE in the amount of \$124 million, \$123 million and \$79 million in 2024, 2023 and 2022, respectively, for its share of technology costs, corporate expenses and other costs. Amounts charged to MidAmerican Funding in 2024 and 2023 were primarily reflected in construction work-in-progress on the Consolidated Balance Sheets as of December 31, 2024 and 2023.

MidAmerican Energy purchases, in the normal course of business at either tariffed or market prices, natural gas transportation and storage capacity services from Northern Natural Gas Company, a wholly owned subsidiary of BHE and coal transportation services from BNSF Railway Company, a wholly owned subsidiary of Berkshire Hathaway. These purchases totaled \$133 million, \$141 million and \$141 million in 2024, 2023 and 2022, respectively.

MHC has a \$300 million revolving credit arrangement carrying interest at the One Month Term Secured Overnight Financing Rate, plus a spread, to borrow from BHE. Outstanding balances are unsecured and due on demand. The outstanding balance was \$13 million at an interest rate of 4.875% as of December 31, 2024, and \$— million as of December 31, 2023, and is reflected as note payable to affiliate on the Consolidated Balance Sheet.

MidAmerican Funding had accounts receivable from affiliates of \$19 million and \$10 million as of December 31, 2024 and 2023, respectively, that are included in other current assets on the Consolidated Balance Sheets. MidAmerican Funding also had accounts payable to affiliates of \$16 million and \$32 million as of December 31, 2024 and 2023, respectively, that are included in accounts payable on the Consolidated Balance Sheets.

MidAmerican Funding is party to a tax-sharing agreement and is part of the Berkshire Hathaway consolidated U.S. federal income tax return. For current federal and state income taxes, MidAmerican Funding had a net receivable from BHE of \$1 million and a net payable to BHE of \$21 million as of December 31, 2024 and 2023, respectively. MidAmerican Funding received net cash payments for federal and state income taxes from BHE totaling \$903 million, \$855 million and \$845 million for the years ended December 31, 2024, 2023 and 2022, respectively.

MidAmerican Funding recognizes the full amount of the funded status for its pension and postretirement plans, and amounts attributable to MidAmerican Funding's affiliates that have not previously been recognized through income are recognized as an intercompany balance with such affiliates. MidAmerican Funding adjusts these balances when changes to the funded status of the respective plans are recognized and does not intend to settle the balances currently. Amounts receivable from affiliates attributable to the funded status of employee benefit plans totaled \$70 million and \$82 million as of December 31, 2024 and 2023, respectively, and are included in other assets on the Consolidated Balance Sheets. Similar amounts payable to affiliates totaled \$68 million and \$55 million as of December 31, 2024 and 2023, respectively, and are included in other long-term liabilities on the Consolidated Balance Sheets. See Note 10 for further information pertaining to pension and postretirement accounting.

The indenture pertaining to MidAmerican Funding's long-term debt restricts MidAmerican Funding from paying a distribution on its equity securities, unless after making such distribution either its debt to total capital ratio does not exceed 0.67:1.0 and its interest coverage ratio is not less than 2.2:1.0 or its senior secured long-term debt rating is at least BBB or its equivalent. MidAmerican Funding may seek a release from this restriction upon delivery to the indenture trustee of written confirmation from the ratings agencies that without this restriction MidAmerican Funding's senior secured long-term debt would be rated at least BBB+.

(19) Segment Information

MidAmerican Funding's chief operating decision maker ("CODM") is its President. Net income for each reportable segment is considered by the CODM in allocating resources and capital. The CODM generally considers actual results versus historical results, budgets or forecasts, as well as unique risks and opportunities, when making decisions about the allocation of resources and capital to each reportable segment.

MidAmerican Funding has identified two reportable operating segments: regulated electric and regulated natural gas. The regulated electric segment derives most of its revenue from regulated retail sales of electricity to residential, commercial, and industrial customers and from wholesale sales. The regulated natural gas segment derives most of its revenue from regulated retail sales of natural gas to residential, commercial, and industrial customers and also obtains revenue by transporting natural gas owned by others through its distribution system. Pricing for regulated electric and regulated natural gas sales are established separately by regulatory agencies; therefore, management also reviews each segment separately to make decisions regarding allocation of resources and in evaluating performance. Common operating costs are allocated to each segment based on certain factors, which primarily relate to the nature of the cost.

The following tables provide information on a reportable segment basis for the year ended December 31 (in millions):

	2024			
	Electric	Natural Gas	Other ⁽¹⁾	Total
Operating revenue	\$ 2,584	\$ 658	\$ 9	\$ 3,251
Cost of sales	430	367	—	797
Operations and maintenance	757	121	1	879
Depreciation and amortization	935	66	—	1,001
Property and other taxes	152	14	—	166
Operating income	310	90	8	408
Interest expense	(387)	(30)	(17)	(434)
Interest and dividend income	37	3	—	40
Income tax expense (benefit)	(841)	(1)	(1)	(843)
Other segment items ⁽²⁾	129	7	(2)	134
Net income	<u>\$ 930</u>	<u>\$ 71</u>	<u>\$ (10)</u>	<u>\$ 991</u>
Capital expenditures	<u>\$ 1,580</u>	<u>\$ 114</u>	<u>\$ 10</u>	<u>\$ 1,704</u>
Total assets	<u>\$ 25,350</u>	<u>\$ 2,035</u>	<u>\$ 5</u>	<u>\$ 27,390</u>
Goodwill	<u>\$ 1,191</u>	<u>\$ 79</u>	<u>\$ —</u>	<u>\$ 1,270</u>
	2023			
	Electric	Natural Gas	Other ⁽¹⁾	Total
Operating revenue	\$ 2,673	\$ 713	\$ 7	\$ 3,393
Cost of sales	501	451	—	952
Operations and maintenance	711	138	2	851
Depreciation and amortization	846	62	—	908
Property and other taxes	144	17	—	161
Operating income	471	45	5	521
Interest expense	(320)	(26)	(16)	(362)
Interest and dividend income	22	2	—	24
Income tax expense (benefit)	(676)	(14)	(5)	(695)
Other segment items ⁽²⁾	80	15	7	102
Net income	<u>\$ 929</u>	<u>\$ 50</u>	<u>\$ 1</u>	<u>\$ 980</u>
Capital expenditures	<u>\$ 1,683</u>	<u>\$ 149</u>	<u>\$ 1</u>	<u>\$ 1,833</u>
Total assets	<u>\$ 24,525</u>	<u>\$ 1,979</u>	<u>\$ 5</u>	<u>\$ 26,509</u>
Goodwill	<u>\$ 1,191</u>	<u>\$ 79</u>	<u>\$ —</u>	<u>\$ 1,270</u>

	2022			
	Electric	Natural Gas	Other ⁽¹⁾	Total
Operating revenue	\$ 2,988	\$ 1,030	\$ 7	\$ 4,025
Cost of sales	679	762	1	1,442
Operations and maintenance	692	135	1	828
Depreciation and amortization	1,112	56	—	1,168
Property and other taxes	133	16	—	149
Operating income	372	61	5	438
Interest expense	(290)	(23)	(20)	(333)
Interest and dividend income	6	1	—	7
Income tax expense (benefit)	(779)	9	(6)	(776)
Other segment items ⁽²⁾	64	—	(5)	59
Net income	<u>\$ 931</u>	<u>\$ 30</u>	<u>\$ (14)</u>	<u>\$ 947</u>
Capital expenditures	<u>\$ 1,742</u>	<u>\$ 127</u>	<u>\$ —</u>	<u>\$ 1,869</u>
Total assets	<u>\$ 23,283</u>	<u>\$ 1,963</u>	<u>\$ 8</u>	<u>\$ 25,254</u>
Goodwill	<u>\$ 1,191</u>	<u>\$ 79</u>	<u>\$ —</u>	<u>\$ 1,270</u>

(1) The differences between the reportable segment amounts and the consolidated amounts, described as Other, consists of the nonregulated subsidiaries of MidAmerican Funding not engaged in the energy business.

(2) Other segment items include allowance for borrowed and equity funds, gains (losses) on marketable securities and other income (expense).

Nevada Power Company and its subsidiaries
Consolidated Financial Section

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

The following is management's discussion and analysis of certain significant factors that have affected the consolidated financial condition and results of operations of Nevada Power during the periods included herein. Explanations include management's best estimate of the impact of weather, customer growth, usage trends and other factors. This discussion should be read in conjunction with Nevada Power's historical Consolidated Financial Statements and Notes to Consolidated Financial Statements in Item 8 of this Form 10-K. Nevada Power's actual results in the future could differ significantly from the historical results.

Results of Operations

Overview

Net income for the year ended December 31, 2024 was \$349 million, an increase of \$89 million, or 34%, compared to 2023, primarily due to higher utility margin, lower depreciation and amortization expense, higher capitalized interest and allowance for equity funds. These items were partially offset by unfavorable interest and dividend income, higher income tax expense, partially offset by increased federal income tax credits and higher interest expense. Utility margin increased primarily due to higher retail customer volumes, higher retail rates from the 2023 regulatory rate review with new rates effective January 2024 and higher power purchase agreement sales, partially offset by lower other revenue from expiring regulatory amortizations and the impact of lower regulatory amortizations approved in the 2023 regulatory rate review. Retail customer volumes, including distribution only service customers, increased 7.8% primarily due to the favorable impact of weather, higher customer usage and an increase in the average number of customers. Energy generated increased 14% for 2024 compared to 2023 primarily due to higher natural gas-fueled generation. Wholesale electricity sales volumes increased 102% and purchased electricity volumes increased 4%.

Net income for the year ended December 31, 2023 was \$260 million, a decrease of \$38 million, or 13%, compared to 2022, primarily due to lower utility margin, higher interest expense, higher depreciation and amortization expense and higher operations and maintenance expense. These items were partially offset by higher capitalized interest and allowance for equity funds, favorable interest and dividend income, lower income tax expense and higher cash surrender value of corporate-owned life insurance policies. Utility margin decreased primarily due to lower retail customer volumes and lower regulatory-related revenue deferrals due to an unfavorable outcome in the 2023 regulatory rate review, partially offset by higher other retail revenue. Retail customer volumes, including distribution only service customers, decreased 2.4% primarily due to the unfavorable impact of weather, offset by an increase in the average number of customers. Energy generated increased 5% for 2023 compared to 2022 primarily due to higher natural gas-fueled generation. Wholesale electricity sales volumes decreased 61% and purchased electricity volumes decreased 14%.

Non-GAAP Financial Measure

Management utilizes various key financial measures that are prepared in accordance with GAAP, as well as non-GAAP financial measures such as utility margin, to help evaluate results of operations. Utility margin is calculated as operating revenue less cost of fuel and energy, which are captions presented on the Consolidated Statements of Operations.

Nevada Power's cost of fuel and energy is generally recovered from its retail customers through regulatory recovery mechanisms and, as a result, changes in Nevada Power's expenses included in regulatory recovery mechanisms result in comparable changes to revenue. As such, management believes utility margin more appropriately and concisely explains results of operations rather than a discussion of revenue and cost of fuel and energy separately. Management believes the presentation of utility margin provides meaningful and valuable insight into the information management considers important to understanding the business and a measure of comparability to others in the industry.

Utility margin is not a measure calculated in accordance with GAAP and should be viewed as a supplement to, and not a substitute for, operating income, which is the most directly comparable financial measure prepared in accordance with GAAP. The following table provides a reconciliation of utility margin to operating income for the years ended December 31 (in millions):

	2024	2023	Change		2023	2022	Change	
Utility margin:								
Operating revenue	\$ 2,873	\$ 3,088	\$ (215)	(7)%	\$ 3,088	\$ 2,630	\$ 458	17 %
Cost of fuel and energy	1,608	1,942	(334)	(17)	1,942	1,427	515	36
Utility margin	1,265	1,146	119	10	1,146	1,203	(57)	(5)
Operations and maintenance	311	312	(1)	—	312	303	9	3
Depreciation and amortization	376	432	(56)	(13)	432	417	15	4
Property and other taxes	58	56	2	4	56	53	3	6
Operating income	\$ 520	\$ 346	\$ 174	50 %	\$ 346	\$ 430	\$ (84)	(20)%

Utility Margin

A comparison of key operating results related to utility margin is as follows for the years ended December 31:

	2024	2023	Change		2023	2022	Change	
Utility margin (in millions):								
Operating revenue	\$ 2,873	\$ 3,088	\$ (215)	(7)%	\$ 3,088	\$ 2,630	\$ 458	17 %
Cost of fuel and energy	1,608	1,942	(334)	(17)	1,942	1,427	515	36
Utility margin	<u>\$ 1,265</u>	<u>\$ 1,146</u>	<u>\$ 119</u>	10 %	<u>\$ 1,146</u>	<u>\$ 1,203</u>	<u>\$ (57)</u>	(5)%
Sales (GWhs):								
Residential	10,535	9,584	951	10 %	9,584	10,299	(715)	(7)%
Commercial	5,045	4,807	238	5	4,807	4,904	(97)	(2)
Industrial	6,356	5,827	529	9	5,827	5,630	197	3
Other	179	179	—	—	179	191	(12)	(6)
Total fully bundled ⁽¹⁾	22,115	20,397	1,718	8	20,397	21,024	(627)	(3)
Distribution only service	2,918	2,831	87	3	2,831	2,786	45	2
Total retail	25,033	23,228	1,805	8	23,228	23,810	(582)	(2)
Wholesale	465	230	235	*	230	586	(356)	(61)
Total GWhs sold	<u>25,498</u>	<u>23,458</u>	<u>2,040</u>	9 %	<u>23,458</u>	<u>24,396</u>	<u>(938)</u>	(4)%
Average number of retail customers (in thousands)	1,035	1,015	20	2 %	1,015	1,001	14	1 %
Average revenue per MWh:								
Retail - fully bundled ⁽¹⁾	\$126.73	\$147.38	\$ (20.65)	(14)%	\$147.38	\$120.21	\$ 27.17	23 %
Wholesale	\$ 30.33	\$ 62.73	\$ (32.40)	(52)%	\$ 62.73	\$ 61.83	\$ 0.90	1 %
Heating degree days	1,798	1,962	(164)	(8)%	1,962	1,904	58	3 %
Cooling degree days	4,557	3,651	906	25 %	3,651	4,016	(365)	(9)%
Sources of energy (GWhs) ⁽²⁾⁽³⁾ :								
Natural gas	15,377	13,719	1,658	12 %	13,719	13,068	651	5 %
Renewables	402	66	336	*	66	69	(3)	(4)
Total energy generated	15,779	13,785	1,994	14	13,785	13,137	648	5
Energy purchased	7,914	7,606	308	4	7,606	8,830	(1,224)	(14)
Total	23,693	21,391	2,302	11 %	21,391	21,967	(576)	(3)%
Average cost of energy per MWh ⁽²⁾⁽⁴⁾ :								
Energy generated	\$ 37.42	\$ 65.25	\$ (27.83)	(43)%	\$ 65.25	\$ 49.82	\$ 15.43	31 %
Energy purchased	\$128.54	\$137.08	\$ (8.54)	(6)%	\$137.08	\$ 87.49	\$ 49.59	57 %

* Not meaningful

(1) Fully bundled includes sales to customers for combined energy, transmission and distribution services.

(2) The average cost of energy per MWh and sources of energy excludes 404, 846 and 1,113 GWhs of natural gas generated energy that is purchased at cost by related parties for the years ended December 31, 2024, 2023 and 2022, respectively.

(3) GWh amounts are net of energy used by the related generating facilities.

(4) The average cost of energy per MWh includes only the cost of fuel associated with the generating facilities, purchased power and deferrals.

Year Ended December 31, 2024 Compared to Year Ended December 31, 2023

Utility margin increased \$119 million, or 10%, for 2024 compared to 2023 primarily due to:

- \$118 million of higher electric retail utility margin primarily due to higher retail customer volumes and higher retail rates from the 2023 regulatory rate review with new rates effective January 2024. Retail customer volumes, including distribution only service customers, increased 7.8% primarily due to the favorable impacts of weather, customer usage patterns and an increase in the average number of customers;
- \$13 million of higher power purchase agreement sales from the Dry Lake renewable generation facility;
- \$7 million of higher energy efficiency program revenue (offset in operations and maintenance expense);
- \$4 million of higher energy efficiency implementation revenue and
- \$4 million of higher transmission and wholesale revenue.

The increase in utility margin was partially offset by:

- \$14 million of lower other revenue from expiring regulatory amortizations and
- \$14 million of lower other retail revenue from the impact of regulatory amortizations.

Operations and maintenance decreased \$1 million for 2024 compared to 2023 primarily due to the impact of regulatory amortizations approved in the 2023 regulatory rate review, partially offset by higher plant operations and maintenance expenses, higher energy efficiency program costs (offset in operating revenue) and higher insurance premiums due to additional wildfire and general excess liability coverage.

Depreciation and amortization decreased \$56 million, or 13%, for 2024 compared to 2023 primarily due to lower regulatory amortizations, partially offset by higher amortization from an increased rate for intangible software approved in the 2023 regulatory rate review.

Property and other taxes increased \$2 million, or 4%, for 2024 compared to 2023 primarily due to a decrease in the amount of abatements available, higher plant placed in-service and an increase in commerce and franchise tax from higher revenue.

Interest expense increased \$11 million, or 6%, for 2024 compared to 2023 primarily due to higher long-term debt and higher average interest rate.

Capitalized interest and allowance for equity funds increased \$5 million, or 11%, for 2024 compared to 2023 primarily due to higher construction work-in-progress.

Interest and dividend income decreased \$48 million, or 67%, for 2024 compared to 2023 primarily due to unfavorable interest income, mainly from lower carrying charges on regulatory balances.

Other, net was favorable by \$4 million for 2024 compared to 2023 primarily due to lower pension expense.

Income tax expense increased \$35 million for 2024 compared to 2023 primarily due to higher pretax income and the effects of ratemaking, partially offset by higher federal income tax credits. The effective tax rate was 14% in 2024 and 8% in 2023 and increased primarily due to the effects of ratemaking, offset by higher federal tax credits.

Year Ended December 31, 2023 Compared to Year Ended December 31, 2022

Utility margin decreased \$57 million for 2023 compared to 2022 primarily due to:

- \$44 million of lower electric retail utility margin primarily due to lower retail customer volumes. Retail customer volumes, including distribution only service customers, decreased 2.4% primarily due to the unfavorable impact of weather, offset by an increase in the average number of customers and
- \$31 million of lower regulatory-related revenue deferrals due to an unfavorable outcome in the 2023 regulatory rate review.

The decrease in utility margin was partially offset by:

- \$11 million of higher energy efficiency program rates (offset in operations and maintenance expense) and
- \$5 million of higher other retail revenue.

Operations and maintenance increased \$9 million, or 3%, for 2023 compared to 2022 primarily due to higher energy efficiency program costs (offset in operating revenue), increased plant operations and maintenance expenses, higher technology costs, higher customer service operations expenses, regulatory disallowances from the 2023 regulatory rate review and higher insurance premiums due to additional wildfire and general excess liability coverage, partially offset by lower earnings sharing.

Depreciation and amortization increased \$15 million, or 4%, for 2023 compared to 2022 primarily due to higher plant placed in-service.

Property and other taxes increased \$3 million, or 6%, for 2023 compared to 2022 primarily due to a decrease in the amount of abatements available and an increase in commerce and franchise tax from higher revenue.

Interest expense increased \$31 million, or 19% for 2023 compared to 2022 primarily due to higher long-term debt and higher average interest rate.

Capitalized interest increased \$17 million for 2023 compared to 2022 primarily due to higher construction work-in-progress.

Allowance for equity funds increased \$10 million, or 91%, for 2023 compared to 2022 primarily due to higher construction work-in-progress.

Interest and dividend income increased \$25 million, or 53%, for 2023 compared to 2022 primarily due to favorable interest income, mainly from carrying charges on regulatory balances.

Other, net increased \$11 million for 2023 compared to 2022 primarily due to favorable cash surrender value of corporate-owned life insurance policies.

Income tax expense decreased \$14 million, or 39%, for 2023 compared to 2022 primarily due to lower pretax income and the effects of ratemaking. The effective tax rate was 8% in 2023 and 11% in 2022.

Liquidity and Capital Resources

As of December 31, 2024, Nevada Power's total net liquidity was \$623 million as follows (in millions):

Cash and cash equivalents	\$	23
Credit facilities ⁽¹⁾		600
Total net liquidity	\$	623
Credit facilities:		
Maturity dates		2027

(1) Refer to Note 7 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for further discussion regarding Nevada Power's credit facility.

Operating Activities

Net cash flows from operating activities for the years ended December 31, 2024 and 2023 were \$989 million and \$761 million, respectively. The change was primarily due to lower payments related to fuel and energy costs and the timing of payments for operating costs, partially offset by higher income tax payments, lower collections from customers, higher interest payments and decreased vendor deposits.

Net cash flows from operating activities for the years ended December 31, 2023 and 2022 were \$761 million and \$355 million, respectively. The change was primarily due to higher collections from customers, increased customer and vendor deposits and higher income tax refunds, partially offset by the timing of payments for operating costs, higher payments related to fuel and energy costs and higher interest payments.

The timing of Nevada Power's income tax cash flows from period to period can be significantly affected by the estimated federal income tax payment methods selected and assumptions made for each payment date.

Investing Activities

Net cash flows from investing activities for the years ended December 31, 2024 and 2023 were \$(1,099) million and \$(1,309) million, respectively. The change was primarily due to decreased capital expenditures, offset by decreased proceeds from an affiliate note receivable. Refer to "Future Uses of Cash" for further discussion of capital expenditures.

Net cash flows from investing activities for the years ended December 31, 2023 and 2022 were \$(1,309) million and \$(862) million, respectively. The change was primarily due to increased capital expenditures, offset by proceeds from an affiliate note receivable. Refer to "Future Uses of Cash" for further discussion of capital expenditures.

Financing Activities

Net cash flows from financing activities for the years ended December 31, 2024 and 2023 were \$115 million and \$525 million, respectively. The change was primarily due to a decrease in proceeds from long-term debt, lower contributions from NV Energy, Inc. and higher dividends paid to NV Energy, Inc., partially offset by a decrease in repayments of long-term debt.

Net cash flows from financing activities for the years ended December 31, 2023 and 2022 were \$525 million and \$522 million, respectively. The change was primarily due to higher contributions from NV Energy, Inc. and lower repayments of short-term debt, partially offset by higher repayments of long-term debt, lower proceeds from the issuance of long-term debt and higher dividends paid to NV Energy, Inc.

In February 2025, Nevada Power declared and paid a dividend to NV Energy, Inc. of \$185 million.

Debt Authorizations

Nevada Power currently has an effective shelf registration statement with the SEC to issue an additional \$1.8 billion of general and refunding mortgage securities through December 19, 2027. Additionally, Nevada Power's ability to issue debt is primarily impacted by its financing authority from the PUCN. As of December 31, 2024, Nevada Power has financing authority from the PUCN consisting of the ability to issue long-term and short-term debt securities so long as the total amount of debt outstanding (excluding borrowings under Nevada Power's \$600 million secured credit facility) does not exceed \$5.5 billion and to issue common and preferred stock so long as the total amounts outstanding do not exceed \$6.5 billion and \$800 million, respectively, as measured at the end of each calendar quarter. Nevada Power's revolving credit facility contains a financial maintenance covenant which Nevada Power was in compliance with as of December 31, 2024. In addition, certain financing agreements contain covenants which are currently suspended as Nevada Power's senior secured debt is rated investment grade. However, if Nevada Power's senior secured debt ratings fall below investment grade by either Moody's Investor Service or Standard & Poor's, Nevada Power would be subject to limitations under these covenants.

General and Refunding Mortgage Securities

To the extent Nevada Power has the ability to issue debt under the most restrictive covenants in its financing agreements and has financing authority to do so from the PUCN, Nevada Power's ability to issue secured debt is limited by the amount of bondable property or retired bonds that can be used to issue debt under Nevada Power's indenture.

Nevada Power's indenture creates a lien on substantially all of Nevada Power's properties in Nevada. As of December 31, 2024, \$11.5 billion of Nevada Power's assets were pledged. Nevada Power had the capacity to issue \$4.0 billion of additional general and refunding mortgage securities as of December 31, 2024, determined on the basis of 70% of net utility property additions. Property additions include plant-in-service and specific assets in construction work-in-progress. The amount of bond capacity listed above does not include eligible property in construction work-in-progress. Nevada Power also has the ability to release property from the lien of Nevada Power's indenture on the basis of net property additions, cash or retired bonds. To the extent Nevada Power releases property from the lien of Nevada Power's indenture, it will reduce the amount of securities issuable under the indenture.

Long-Term Debt

In February 2025, Nevada Power issued \$300 million of its 6.25% Fixed-to-Fixed Reset Rate Junior Subordinated Notes due 2055. Nevada Power will pay interest on the Notes at a rate of 6.25% through May 2030, subject to a reset every 5 years. Nevada Power intends to use the net proceeds from the sale of the notes to fund capital expenditures and for general corporate purposes.

Future Uses of Cash

Nevada Power has available a variety of sources of liquidity and capital resources, both internal and external, including net cash flows from operating activities, public and private debt offerings, the use of secured revolving credit facilities, capital contributions and other sources. These sources are expected to provide funds required for current operations, capital expenditures, debt retirements and other capital requirements. The availability and terms under which Nevada Power has access to external financing depends on a variety of factors, including Nevada Power's credit ratings, investors' judgment of risk associated with Nevada Power and conditions in the overall capital markets, including the condition of the utility industry.

Capital Expenditures

Capital expenditure needs are reviewed regularly by management and may change significantly as a result of these reviews, which may consider, among other factors, changes in environmental and other rules and regulations; impacts to customers' rates; outcomes of regulatory proceedings; changes in income tax laws; general business conditions; load projections; system reliability standards; the cost and efficiency of construction labor, equipment and materials; commodity prices; and the cost and availability of capital. Prudently incurred expenditures for compliance-related items such as pollution control technologies, replacement generation and associated operating costs are generally incorporated into Nevada Power's regulated retail rates. Expenditures for certain assets may ultimately include acquisition of existing assets.

Historical and forecasted capital expenditures, each of which exclude amounts for non-cash equity AFUDC and other non-cash items, for the years ending December 31 are as follows (in millions):

	Historical			Forecast		
	2022	2023	2024	2025	2026	2027
Electric distribution	\$ 236	\$ 352	\$ 347	\$ 346	\$ 465	\$ 426
Electric transmission	110	124	221	711	732	818
Solar generation	85	188	28	3	34	35
Electric battery storage	8	338	14	42	11	1
Other	323	407	493	207	181	145
Total	<u>\$ 762</u>	<u>\$ 1,409</u>	<u>\$ 1,103</u>	<u>\$ 1,309</u>	<u>\$ 1,423</u>	<u>\$ 1,425</u>

Nevada Power received or is seeking PUCN approval through its recent IRP filings for an increase in solar generation and electric transmission and has included estimates from its IRP filings as well as potential future filings in its forecast capital expenditures for 2025 through 2027. These estimates are likely to change as a result of the RFP process, continued evaluation and future IRP filing refinements. Nevada Power's historical and forecast capital expenditures include the following:

- Electric distribution includes both growth projects and operating expenditures consisting of routine expenditures for distribution needed to serve existing and expected demand.
- Electric transmission includes both growth projects and operating expenditures. Growth projects primarily relate to the Nevada Utilities' Greenlink Nevada transmission expansion program totaling \$181 million for 2024, \$62 million for 2023 and \$24 million for 2022. Planned spending for the expansion program expected to be placed in-service in 2027 and 2028 totals \$682 million in 2025, \$696 million in 2026 and \$750 million in 2027. Operating expenditures consist of routine expenditures for transmission and other infrastructure needed to serve existing and expected demand.

- Solar generation includes two growth projects and other planned solar generating facilities. The first growth project consists of a 150-MW solar photovoltaic facility with an additional 100-MWs of co-located battery storage developed in Clark County, Nevada which commenced commercial operation in May 2024. The second growth project, consists of a 400-MW solar photovoltaic facility with an additional 400-MW of co-located battery storage that is being developed in Churchill County, Nevada with ownership share approved by the PUCN of 10% Nevada Power and 90% Sierra Pacific of which commercial operation of the solar facility is expected by early 2027.
- Electric battery storage includes two growth projects and other planned electric battery storage systems. The first project consists of a 100-MW battery energy storage system co-located with a 150-MW solar photovoltaic facility that was developed in Clark County, Nevada which commenced commercial operation in May 2024. The second growth project consists of a 400-MW battery energy storage system co-located with a 400-MW solar photovoltaic facility that is being developed in Churchill County, Nevada with ownership share approved by the PUCN of 10% Nevada Power and 90% Sierra Pacific of which commercial operation of the battery energy storage system is expected by mid-2026. Also included was a 220-MW grid-tied battery energy storage system that was developed on the site of the retired Reid Gardner generating station in Clark County, Nevada that commenced operations in December 2023.
- Other includes both growth projects and operating expenditures. Growth projects primarily consist of an additional 444 MW of peaking combustion turbines that were approved by the PUCN and developed at the Silverhawk generating facility in Clark County, Nevada. Commercial operation occurred in July 2024. Operating expenditures consist of information technology expenditures, routine expenditures for generation, other operating projects and other infrastructure needed to serve existing and expected demand.

2021 Joint Integrated Resource Plan

In August 2023, the Nevada Utilities filed its Joint Application for approval of the Fifth Amendment to the 2021 Joint Integrated Resource Plan. The Fifth Amendment sought, in part (1) to convert the existing coal-fueled generating facility at North Valmy Generating Station to a cleaner natural gas-fueled generating facility (2) to purchase, install, and operate a company-owned 400 MW solar plant along with a 400 MW, four-hour battery storage system in Northern Nevada; (3) to continue operation of Tracy units 4 and 5 to 2049; (4) to purchase development assets for the 149 MW photovoltaic and 149 MW battery energy storage system Crescent Valley Solar project; (5) to construct the Esmeralda and Amargosa substations transformers; and (6) to construct the necessary infrastructure in the APEX Area Master Plan. The Nevada Utilities sought approval of approximately \$1.8 billion in total costs of new projects of which Nevada Power's share is approximately \$1.0 billion. An order was issued in March 2024 in which the Nevada Utilities filed a motion for clarification and petition for reconsideration. In April 2024, a modified final order was issued, which granted in part and denied in part including the denial of the 149 MW photovoltaic and 149 MW battery energy storage system Crescent Valley Solar project as delineated in the final modified order.

In May 2024, the Nevada Utilities filed its joint Application for approval of the 2024 Joint Integrated Resources Plan. The 2024 joint Application sought, in part (1) the addition of three power purchase agreements for solar generating resources totaling more than 1,000 MW, each with co-located battery storage systems; (2) the addition of 400 MW of company-owned hydrogen-capable natural gas simple cycle combustion turbine peakers at the North Valmy generation station; (3) to approve an update of the Greenlink Nevada Transmission project costs; and (4) to construct the necessary transmission infrastructure to support growing customer demand. In December 2024, the PUCN largely accepted the filing as filed but denied opining on the additional costs associated with the Greenlink Nevada project as all costs expended to construct the previously approved Greenlink Nevada project are subject to a prudency review in the GRC as delineated in the final 2024 Joint Integrated Resource Plan order.

Material Cash Requirements

Nevada Power has cash requirements that may affect its consolidated financial condition that arise primarily from long- and short-term debt (refer to Notes 7 and 8), operating and financing leases (refer to Note 5), purchased electricity contracts (refer to Note 14), fuel contracts (refer to Note 14), construction and other development costs (refer to Liquidity and Capital Resources included within this Item 7 and Note 14) and AROs (refer to Note 11). Refer to the respective referenced note in Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

Nevada Power has cash requirements relating to interest payments of \$3.0 billion on long-term debt, including \$170 million due in 2025.

Regulatory Matters

Nevada Power is subject to comprehensive regulation. Refer to the discussion contained in Item 1 of this Form 10-K for further information regarding Nevada Power's general regulatory framework and current regulatory matters.

Environmental Laws and Regulations

Nevada Power is subject to federal, state and local laws and regulations regarding air quality, climate change, emissions performance standards, water quality, coal ash disposal and other environmental matters that have the potential to impact Nevada Power's current and future operations. In addition to imposing continuing compliance obligations, these laws and regulations provide regulators with the authority to levy substantial penalties for noncompliance including fines, injunctive relief and other sanctions. These laws and regulations are administered by various federal, state and local agencies. Nevada Power believes it is in material compliance with all applicable laws and regulations, although many are subject to interpretation that may ultimately be resolved by the courts. Environmental laws and regulations continue to evolve, and Nevada Power is unable to predict the impact of the changing laws and regulations on its operations and financial results.

Refer to "Environmental Laws and Regulations" in Item 1 of this Form 10-K for further discussion regarding environmental laws and regulations.

Collateral and Contingent Features

Debt of Nevada Power is rated by credit rating agencies. Assigned credit ratings are based on each rating agency's assessment of Nevada Power's ability to, in general, meet the obligations of its issued debt. The credit ratings are not a recommendation to buy, sell or hold securities, and there is no assurance that a particular credit rating will continue for any given period of time.

Nevada Power has no credit rating downgrade triggers that would accelerate the maturity dates of outstanding debt, and a change in ratings is not an event of default under the applicable debt instruments. Nevada Power's secured revolving credit facility does not require the maintenance of a minimum credit rating level in order to draw upon its availability. However, commitment fees and interest rates under the credit facility are tied to credit ratings and increase or decrease when the ratings change. A ratings downgrade could also increase the future cost of commercial paper, short- and long-term debt issuances or new credit facilities.

In accordance with industry practice, certain wholesale agreements, including derivative contracts, contain credit support provisions that in part base certain collateral requirements on credit ratings for unsecured debt as reported by one or more of the recognized credit rating agencies. These agreements may either specifically provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed specified rating-dependent threshold levels ("credit-risk-related contingent features") or provide the right for counterparties to demand "adequate assurance," or in some cases terminate the contract, in the event of a material adverse change in creditworthiness. These rights can vary by contract and by counterparty. As of December 31, 2024, the applicable credit ratings obtained from recognized credit rating agencies were investment grade. If all credit-risk-related contingent features or adequate assurance provisions for these agreements had been triggered as of December 31, 2024, Nevada Power would have been required to post \$57 million of additional collateral. Nevada Power's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation, or other factors.

Inflation

Historically, overall inflation and changing prices in the economies where Nevada Power operates has not had a significant impact on Nevada Power's consolidated financial results. Nevada Power operates under a cost-of-service based rate-setting structure administered by the PUCN and the FERC. Under this rate-setting structure, Nevada Power is allowed to include prudent costs in its rates, including the impact of inflation after Nevada Power experiences cost increases. Fuel and purchase power costs are recovered through a balancing account, minimizing the impact of inflation related to these costs. Nevada Power attempts to minimize the potential impact of inflation on its operations through the use of periodic rate adjustments for fuel and energy costs, by employing prudent risk management and hedging strategies and by considering, among other areas, its impact on purchases of energy, operating expenses, materials and equipment costs, contract negotiations, future capital spending programs and long-term debt issuances. There can be no assurance that such actions will be successful.

New Accounting Pronouncements

For a discussion of new accounting pronouncements affecting Nevada Power, refer to Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Critical Accounting Estimates

Certain accounting measurements require management to make estimates and judgments concerning transactions that will be settled several years in the future. Amounts recognized on the Consolidated Financial Statements based on such estimates involve numerous assumptions subject to varying and potentially significant degrees of judgment and uncertainty and will likely change in the future as additional information becomes available. The following critical accounting estimates are impacted significantly by Nevada Power's methods, judgments and assumptions used in the preparation of the Consolidated Financial Statements and should be read in conjunction with Nevada Power's Summary of Significant Accounting Policies included in Nevada Power's Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Accounting for the Effects of Certain Types of Regulation

Nevada Power prepares its Consolidated Financial Statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, Nevada Power defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in regulated rates occur.

Nevada Power continually evaluates the applicability of the guidance for regulated operations and whether its regulatory assets and liabilities are probable of inclusion in future regulated rates by considering factors such as a change in the regulator's approach to setting rates from cost-based ratemaking to another form of regulation, other regulatory actions or the impact of competition that could limit Nevada Power's ability to recover its costs. Nevada Power believes its application of the guidance for regulated operations is appropriate and its existing regulatory assets and liabilities are probable of inclusion in future regulated rates. The evaluation reflects the current political and regulatory climate at both the federal and state levels. If it becomes no longer probable that the deferred costs or income will be included in future regulated rates, the related regulatory assets and liabilities will be written off to net income, returned to customers or re-established as AOCI. Total regulatory assets were \$0.6 billion and total regulatory liabilities were \$1.0 billion as of December 31, 2024. Refer to Nevada Power's Note 6 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding Nevada Power's regulatory assets and liabilities.

Impairment of Long-Lived Assets

Nevada Power evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or when the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value and any resulting impairment loss is reflected on the Consolidated Statements of Operations. As substantially all property, plant and equipment was used in regulated businesses as of December 31, 2024, the impacts of regulation are considered when evaluating the carrying value of regulated assets.

The estimate of cash flows arising from the future use of an asset, for the purposes of impairment analysis, requires the exercise of judgment. Circumstances that could significantly alter the calculation of fair value or the recoverable amount of an asset may include significant changes in the regulatory environment, the business climate, management's plans, legal factors, market price of the asset, the use of the asset, the physical condition of the asset, future market prices, load growth, competition and many other factors over the life of the asset. Any resulting impairment loss is highly dependent on the underlying assumptions and could significantly affect Nevada Power's results of operations.

Income Taxes

In determining Nevada Power's income taxes, management is required to interpret complex income tax laws and regulations, which includes consideration of regulatory implications imposed by Nevada Power's various regulatory commissions. Nevada Power's income tax returns are subject to continuous examinations by federal, state and local income tax authorities that may give rise to different interpretations of these complex laws and regulations. Due to the nature of the examination process, it generally takes years before these examinations are completed and these matters are resolved. Nevada Power recognizes the tax benefit from an uncertain tax position only if it is more-likely-than-not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the Consolidated Financial Statements from such a position are measured based on the largest benefit that is more-likely-than-not to be realized upon ultimate settlement. Although the ultimate resolution of Nevada Power's federal, state and local income tax examinations is uncertain, Nevada Power believes it has made adequate provisions for these income tax positions. The aggregate amount of any additional income tax liabilities that may result from these examinations is not expected to have a material impact on Nevada Power's consolidated financial results. Refer to Nevada Power's Note 9 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding Nevada Power's income taxes.

It is probable that Nevada Power will pass income tax benefit and expense related to the federal tax rate change from 35% to 21%, certain property related basis differences and other various differences on to its customers. As of December 31, 2024, these amounts were recognized as a net regulatory liability of \$510 million and will be included in regulated rates when the temporary differences reverse.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Nevada Power's Consolidated Balance Sheets include assets and liabilities with fair values that are subject to market risks. Nevada Power's significant market risks are primarily associated with commodity prices, interest rates and the extension of credit to counterparties with which Nevada Power transacts. The following discussion addresses the significant market risks associated with Nevada Power's business activities. Nevada Power has established guidelines for credit risk management. Refer to Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding Nevada Power's contracts accounted for as derivatives.

Commodity Price Risk

Nevada Power is exposed to the impact of market fluctuations in commodity prices and interest rates. Nevada Power is principally exposed to electricity and natural gas market fluctuations primarily through Nevada Power's obligation to serve retail customer load in its regulated service territory. Nevada Power's load and generating facilities represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel required to generate electricity and wholesale electricity that is purchased and sold. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather, market liquidity, generating facility availability, customer usage, storage, and transmission and transportation constraints. The actual cost of fuel and purchased power is recoverable through the deferred energy mechanism. Interest rate risk exists on variable-rate debt and future debt issuances. Nevada Power does not engage in proprietary trading activities. To mitigate a portion of its commodity price risk, Nevada Power uses commodity derivative contracts, which may include forwards, futures, options, swaps and other agreements, to effectively secure future supply or sell future production generally at fixed prices. Nevada Power does not hedge all of its commodity price risk, thereby exposing the unhedged portion to changes in market prices. Nevada Power's exposure to commodity price risk is generally limited by its ability to include commodity costs in regulated rates through its deferred energy mechanism, which is subject to disallowance and regulatory lag that occurs between the time the costs are incurred and when the costs are included in regulated rates, as well as the impact of any customer sharing resulting from cost adjustment mechanisms.

The table that follows summarizes Nevada Power's price risk on commodity contracts accounted for as derivatives and shows the effects of a hypothetical 10% increase and 10% decrease in forward market prices by the expected volumes for these contracts as of that date. The selected hypothetical change does not reflect what could be considered the best or worse case scenarios (dollars in millions).

	Fair Value - Net Asset (Liability)	Estimated Fair Value after Hypothetical Change in Price	
		10% increase	10% decrease
As of December 31, 2024:			
Total commodity derivative contracts	\$ (57)	\$ (53)	\$ (61)
As of December 31, 2023:			
Total commodity derivative contracts	\$ (68)	\$ (61)	\$ (75)

Nevada Power's commodity derivative contracts not designated as hedging contracts are recoverable from customers in regulated rates and therefore, net unrealized gains and losses associated with interim price movements on commodity derivative contracts do not expose Nevada Power to earnings volatility. As of December 31, 2024 and 2023, a net regulatory asset of \$57 million and \$68 million, respectively, was recorded related to the net derivative liability of \$57 million and \$68 million, respectively. The settled cost of these commodity derivative contracts is generally included in regulated rates.

Interest Rate Risk

Nevada Power is exposed to interest rate risk on its outstanding variable-rate short- and long-term debt and future debt issuances. Nevada Power manages its interest rate risk by limiting its exposure to variable interest rates primarily through the issuance of fixed-rate long-term debt and by monitoring market changes in interest rates. As a result of the fixed interest rates, Nevada Power's fixed-rate long-term debt does not expose Nevada Power to the risk of loss due to changes in market interest rates. Additionally, because fixed-rate long-term debt is not carried at fair value on the Consolidated Balance Sheets, changes in fair value would impact earnings and cash flows only if Nevada Power were to reacquire all or a portion of these instruments prior to their maturity. The nature and amount of Nevada Power's short- and long-term debt can be expected to vary from period to period as a result of future business requirements, market conditions and other factors. Refer to Notes 7 and 8 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional discussion of Nevada Power's short- and long-term debt.

As of December 31, 2024 and 2023, Nevada Power had no short- and long-term variable-rate obligations that expose Nevada Power to the risk of increased interest expense in the event of increases in short-term interest rates.

Credit Risk

Nevada Power is exposed to counterparty credit risk associated with wholesale energy supply and marketing activities with other utilities, energy marketing companies, financial institutions and other market participants. Credit risk may be concentrated to the extent Nevada Power's counterparties have similar economic, industry or other characteristics and due to direct and indirect relationships among the counterparties. Before entering into a transaction, Nevada Power analyzes the financial condition of each significant wholesale counterparty, establishes limits on the amount of unsecured credit to be extended to each counterparty and evaluates the appropriateness of unsecured credit limits on an ongoing basis. To further mitigate wholesale counterparty credit risk, Nevada Power enters into netting and collateral arrangements that may include margining and cross-product netting agreements and obtain third-party guarantees, letters of credit and cash deposits. If required, Nevada Power exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

As of December 31, 2024, Nevada Power's aggregate credit exposure from energy related transactions were not material, based on settlement and mark-to-market exposures, net of collateral.

Item 8. Financial Statements and Supplementary Data	
<u>Report of Independent Registered Public Accounting Firm</u>	<u>354</u>
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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Nevada Power Company

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Nevada Power Company and subsidiaries ("Nevada Power") as of December 31, 2024 and 2023, the related consolidated statements of operations, changes in shareholder's equity, and cash flows, for each of the three years in the period ended December 31, 2024, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of Nevada Power as of December 31, 2024 and 2023, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2024, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of Nevada Power's management. Our responsibility is to express an opinion on Nevada Power's financial statements 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 Nevada Power 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Nevada Power is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of Nevada Power's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the 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 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 financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the executive committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the 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.

Regulatory Matters — Effects of Rate Regulation on the Financial Statements — Refer to Note 6 to the financial statements

Critical Audit Matter Description

Nevada Power is subject to rate regulation by a state public service commission as well as the Federal Energy Regulatory Commission (collectively, the "Commissions"), which have jurisdiction with respect to the rates of electric and natural gas companies in the respective service territories where Nevada Power operates. Management has determined its regulated operations meet the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the specialized rules to account for the effects of cost-based rate regulation. Accounting for the economic effects of rate regulation has a pervasive effect on the financial statements.

Regulated rates are subject to regulatory rate-setting processes. Rates are determined, approved, and established based on a cost-of-service basis, which is designed to allow Nevada Power an opportunity to recover its prudently incurred costs of providing services and to earn a reasonable return on its invested capital. Regulatory decisions can have an effect on the recovery of costs, the rate of return earned on investment, and the timing and amount of assets to be recovered by rates. While Nevada Power Company has indicated it expects to recover costs from customers through regulated rates, there is a risk that changes to the Commissions' approach to setting rates or other regulatory actions could limit Nevada Power's ability to recover its costs.

We identified the effects of rate regulation on the financial statements as a critical audit matter due to the significant judgments made by management to support its assertions about affected account balances and disclosures and the high degree of subjectivity involved in assessing the impact of regulatory orders on the financial statements. Management judgments include assessing the likelihood of (1) recovery in future rates of incurred costs and (2) a refund to customers. Given that management's accounting judgments are based on assumptions about the outcome of decisions by the Commissions, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate setting process due to its inherent complexities.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the uncertainty of decisions by the Commissions included the following, among others:

- We evaluated Nevada Power's disclosures related to the effects of rate regulation by testing recorded balances and evaluating regulatory developments.
- We read relevant regulatory orders issued by the Commissions, regulatory statutes filings made by Nevada Power and intervenors, and other external information. We evaluated relevant external information and compared it to certain recorded regulatory asset and liability balances for completeness.
- For certain regulatory matters, we inspected Nevada Power's filings with the Commissions and the filings with the Commissions by intervenors to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedents of the Commissions' treatment of similar costs under similar circumstances.
- We inquired of management about property, plant, and equipment that may be abandoned. We inquired of management to identify projects that are designed to replace assets that may be retired prior to the end of the useful life. We inspected minutes of the board of directors and regulatory orders and other filings with the Commissions to identify any evidence that may contradict management's assertion regarding probability of an abandonment.

/s/ Deloitte & Touche LLP

Las Vegas, Nevada
February 21, 2025

We have served as Nevada Power's auditor since 1987.

NEVADA POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Amounts in millions, except share data)

	As of December 31,	
	2024	2023
ASSETS		
Current assets:		
Cash and cash equivalents	\$ 23	\$ 20
Trade receivables, net	314	374
Inventories	190	129
Income tax receivable	77	—
Regulatory assets	124	586
Prepayments	67	32
Other current assets	23	31
Total current assets	<u>818</u>	<u>1,172</u>
Property, plant and equipment, net	9,401	8,658
Regulatory assets	459	499
Other assets	<u>400</u>	<u>398</u>
Total assets	<u><u>\$ 11,078</u></u>	<u><u>\$ 10,727</u></u>
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities:		
Accounts payable	\$ 343	\$ 466
Accrued interest	46	44
Accrued property, income and other taxes	34	65
Regulatory liabilities	41	43
Customer deposits	93	59
Derivative contracts	53	62
Other current liabilities	50	48
Total current liabilities	<u>660</u>	<u>787</u>
Long-term debt	3,395	3,392
Finance lease obligations	266	279
Regulatory liabilities	997	1,017
Deferred income taxes	802	836
Other long-term liabilities	510	452
Total liabilities	<u>6,630</u>	<u>6,763</u>
Commitments and contingencies (Note 14)		
Shareholder's equity:		
Common stock - \$1.00 stated value, 1,000 shares authorized, issued and outstanding	—	—
Additional paid-in capital	2,943	2,733
Retained earnings	1,506	1,232
Accumulated other comprehensive loss, net	(1)	(1)
Total shareholder's equity	<u>4,448</u>	<u>3,964</u>
Total liabilities and shareholder's equity	<u><u>\$ 11,078</u></u>	<u><u>\$ 10,727</u></u>

The accompanying notes are an integral part of these consolidated financial statements.

NEVADA POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2024	2023	2022
Operating revenue	\$ 2,873	\$ 3,088	\$ 2,630
Operating expenses:			
Cost of fuel and energy	1,608	1,942	1,427
Operations and maintenance	311	312	303
Depreciation and amortization	376	432	417
Property and other taxes	58	56	53
Total operating expenses	2,353	2,742	2,200
Operating income	520	346	430
Other income (expense):			
Interest expense	(207)	(196)	(165)
Capitalized interest	20	25	8
Allowance for equity funds	31	21	11
Interest and dividend income	24	72	47
Other, net	18	14	3
Total other income (expense)	(114)	(64)	(96)
Income before income tax expense (benefit)	406	282	334
Income tax expense (benefit)	57	22	36
Net income	\$ 349	\$ 260	\$ 298

The accompanying notes are an integral part of these consolidated financial statements.

NEVADA POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY
(Amounts in millions, except shares)

	Common Stock		Other	Retained	Accumulated	Total
	Shares	Amount	Paid-in	Earnings	Other	Shareholder's
			Capital		Comprehensive	Equity
					Loss, Net	
Balance, December 31, 2021	1,000	\$ —	\$ 2,308	\$ 724	\$ (2)	\$ 3,030
Net income	—	—	—	298	—	298
Contributions	—	—	25	—	—	25
Other equity transactions	—	—	—	—	1	1
Balance, December 31, 2022	1,000	—	2,333	1,022	(1)	3,354
Net income	—	—	—	260	—	260
Dividends declared	—	—	—	(50)	—	(50)
Contributions	—	—	400	—	—	400
Balance, December 31, 2023	1,000	—	2,733	1,232	(1)	3,964
Net income	—	—	—	349	—	349
Dividends declared	—	—	—	(75)	—	(75)
Contributions	—	—	210	—	—	210
Balance, December 31, 2024	1,000	\$ —	\$ 2,943	\$ 1,506	\$ (1)	\$ 4,448

The accompanying notes are an integral part of these consolidated financial statements.

NEVADA POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Amounts in millions)

	Years Ended December 31,		
	2024	2023	2022
Cash flows from operating activities:			
Net income	\$ 349	\$ 260	\$ 298
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	376	432	417
Allowance for equity funds	(31)	(21)	(11)
Deferred energy	470	14	(541)
Amortization of deferred energy	(5)	40	160
Other changes in regulatory assets and liabilities	(33)	(13)	(15)
Deferred income taxes and amortization of investment tax credits	(8)	26	49
Other, net	(4)	(1)	8
Changes in other operating assets and liabilities:			
Trade receivables and other assets	43	(3)	(178)
Inventories	(60)	(36)	(29)
Accrued property, income and other taxes	(116)	39	21
Accounts payable and other liabilities	8	24	176
Net cash flows from operating activities	<u>989</u>	<u>761</u>	<u>355</u>
Cash flows from investing activities:			
Capital expenditures	(1,103)	(1,409)	(762)
Proceeds from sale of marketable securities	4	—	—
Net proceeds from (issuance of) affiliate note receivable	—	100	(100)
Net cash flows from investing activities	<u>(1,099)</u>	<u>(1,309)</u>	<u>(862)</u>
Cash flows from financing activities:			
Proceeds from long-term debt	—	494	694
Repayments of long-term debt	—	(300)	—
Net repayments of short-term debt	—	—	(180)
Dividends paid	(75)	(50)	—
Contributions from parent	210	400	25
Other, net	(20)	(19)	(17)
Net cash flows from financing activities	<u>115</u>	<u>525</u>	<u>522</u>
Net change in cash and cash equivalents and restricted cash and cash equivalents	5	(23)	15
Cash and cash equivalents and restricted cash and cash equivalents at beginning of period	37	60	45
Cash and cash equivalents and restricted cash and cash equivalents at end of period	<u>\$ 42</u>	<u>\$ 37</u>	<u>\$ 60</u>

The accompanying notes are an integral part of these consolidated financial statements.

NEVADA POWER COMPANY AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Organization and Operations

Nevada Power Company and its subsidiaries ("Nevada Power"), is a wholly owned subsidiary of NV Energy, Inc. ("NV Energy"), a holding company that also owns Sierra Pacific Power Company and its subsidiaries ("Sierra Pacific") and certain other subsidiaries. Nevada Power is a U.S. regulated electric utility company serving retail customers, including residential, commercial and industrial customers primarily in Las Vegas, North Las Vegas, Henderson and adjoining areas. NV Energy is an indirect wholly owned subsidiary of Berkshire Hathaway Energy Company ("BHE"). BHE is a holding company based in Des Moines, Iowa that has investments in subsidiaries principally engaged in energy businesses. BHE is a wholly owned subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway").

(2) Summary of Significant Accounting Policies

Basis of Consolidation and Presentation

The Consolidated Financial Statements include the accounts of Nevada Power and its subsidiaries in which it holds a controlling financial interest as of the financial statement date. Intercompany accounts and transactions have been eliminated. The Consolidated Statements of Comprehensive Income have been omitted as net income equals comprehensive income for the years ended December 31, 2024, 2023 and 2022.

Use of Estimates in Preparation of Financial Statements

The preparation of the Consolidated Financial Statements in conformity with accounting principles generally accepted in the United States of America ("GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the period. These estimates include, but are not limited to, the effects of regulation; recovery of long-lived assets; certain assumptions made in accounting for pension and other postretirement benefits; asset retirement obligations ("AROs"); income taxes; unbilled revenue; valuation of certain financial assets and liabilities, including derivative contracts; and accounting for contingencies. Actual results may differ from the estimates used in preparing the Consolidated Financial Statements.

Accounting for the Effects of Certain Types of Regulation

Nevada Power prepares its Consolidated Financial Statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, Nevada Power defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in regulated rates occur. If it becomes no longer probable that the deferred costs or income will be included in future regulated rates, the related regulatory assets and liabilities will be written off to net income, returned to customers or re-established as accumulated other comprehensive income (loss) ("AOCI").

Fair Value Measurements

As defined under GAAP, fair value is the price that would be received to sell an asset or paid to transfer a liability between market participants in the principal market or in the most advantageous market when no principal market exists. Adjustments to transaction prices or quoted market prices may be required in illiquid or disorderly markets in order to estimate fair value. Different valuation techniques may be appropriate under the circumstances to determine the value that would be received to sell an asset or paid to transfer a liability in an orderly transaction. Market participants are assumed to be independent, knowledgeable, able and willing to transact an exchange and not under duress. Nonperformance or credit risk is considered when determining fair value. Considerable judgment may be required in interpreting market data used to develop the estimates of fair value. Accordingly, estimates of fair value presented herein are not necessarily indicative of the amounts that could be realized in a current or future market exchange.

Cash and Cash Equivalents and Restricted Cash

Cash equivalents consist of funds invested in money market mutual funds, U.S. Treasury Bills and other investments with a maturity of three months or less when purchased. Cash and cash equivalents exclude amounts where availability is restricted by legal requirements, loan agreements or other contractual provisions. Restricted cash and cash equivalents consist of funds restricted by the Public Utilities Commission of Nevada ("PUCN") for a certain renewable energy contract. A reconciliation of cash and cash equivalents and restricted cash and cash equivalents as of December 31, 2024 and December 31, 2023, as presented on the Consolidated Statements of Cash Flows is outlined below and disaggregated by the line items in which they appear on the Consolidated Balance Sheets (in millions):

	As of December 31,	
	2024	2023
Cash and cash equivalents	\$ 23	\$ 20
Restricted cash and cash equivalents included in other current assets	19	17
Total cash and cash equivalents and restricted cash and cash equivalents	<u>\$ 42</u>	<u>\$ 37</u>

Allowance for Credit Losses

Trade receivables are primarily short-term in nature with stated collection terms of less than one year from the date of origination and are stated at the outstanding principal amount, net of an estimated allowance for credit losses. The allowance for credit losses is based on Nevada Power's assessment of the collectability of amounts owed to Nevada Power by its customers. This assessment requires judgment regarding the ability of customers to pay or the outcome of any pending disputes. In measuring the allowance for credit losses for trade receivables, Nevada Power primarily utilizes credit loss history. However, Nevada Power may adjust the allowance for credit losses to reflect current conditions and reasonable and supportable forecasts that deviate from historical experience. Nevada Power also has the ability to assess deposits on customers who have delayed payments or who are deemed to be a credit risk. The changes in the balance of the allowance for credit losses, which is included in trade receivables, net on the Consolidated Balance Sheets, is summarized as follows for the years ended December 31, (in millions):

	2024	2023	2022
Beginning balance	\$ 20	\$ 20	\$ 18
Charged to operating costs and expenses, net	19	18	14
Write-offs, net	(22)	(18)	(12)
Ending balance	<u>\$ 17</u>	<u>\$ 20</u>	<u>\$ 20</u>

Derivatives

Nevada Power employs a number of different derivative contracts, which may include forwards, futures, options, swaps and other agreements, to manage its commodity price and interest rate risk. Derivative contracts are recorded on the Consolidated Balance Sheets as either assets or liabilities and are stated at estimated fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by GAAP. Derivative balances reflect offsetting permitted under master netting agreements with counterparties and cash collateral paid or received under such agreements.

Commodity derivatives used in normal business operations that are settled by physical delivery, among other criteria, are eligible for and may be designated as normal purchases or normal sales. Normal purchases or normal sales contracts are not marked-to-market and settled amounts are recognized as cost of fuel, energy and capacity on the Consolidated Statements of Operations.

For Nevada Power's derivative contracts, the settled amount is generally included in regulated rates. Accordingly, the net unrealized gains and losses associated with interim price movements on contracts that are accounted for as derivatives and probable of inclusion in regulated rates are recorded as regulatory assets and liabilities. For a derivative contract not probable of inclusion in rates, changes in the fair value are recognized in earnings.

Inventories

Inventories consist mainly of materials and supplies totaling \$190 million and \$129 million as of December 31, 2024 and 2023. The cost is determined using the average cost method. Materials are charged to inventory when purchased and are expensed or capitalized to construction work in process, as appropriate, when used.

Property, Plant and Equipment, Net

General

Additions to property, plant and equipment are recorded at cost. Nevada Power capitalizes all construction-related material, direct labor and contract services, as well as indirect construction costs. Indirect construction costs include debt allowance for funds used during construction ("AFUDC"), and equity AFUDC, as applicable. The cost of additions and betterments are capitalized, while costs incurred that do not improve or extend the useful lives of the related assets are generally expensed. The cost of repairs and minor replacements are charged to expense when incurred with the exception of costs for generation plant maintenance under certain long-term service agreements. Costs under these agreements are expensed straight-line over the term of the agreements as approved by the PUCN.

Depreciation and amortization are generally computed by applying the composite or straight-line method based on either estimated useful lives or mandated recovery periods as prescribed by Nevada Power's various regulatory authorities. Depreciation studies are completed by Nevada Power to determine the appropriate group lives, net salvage and group depreciation rates. These studies are reviewed and rates are ultimately approved by the applicable regulatory commission. Net salvage includes the estimated future residual values of the assets and any estimated removal costs recovered through approved depreciation rates. Estimated removal costs are recorded as a non-current regulatory liability on the Consolidated Balance Sheets. As actual removal costs are incurred, the associated liability is reduced.

Generally when Nevada Power retires or sells a component of regulated property, plant and equipment depreciated using the composite method, it charges the original cost, net of any proceeds from the disposition, to accumulated depreciation. Any gain or loss on disposals of all other assets is recorded through earnings with the exception of material gains or losses on regulated property, plant and equipment depreciated on a straight-line basis, which is then recorded to a regulatory liability or asset, respectively.

Debt and equity AFUDC, which represent the estimated costs of debt and equity funds necessary to finance the construction of regulated facilities, are capitalized as a component of property, plant and equipment, with offsetting credits to the Consolidated Statements of Operations. The rate applied to construction costs is the lower of the PUCN allowed rate of return and rates computed based on guidelines set forth by the Federal Energy Regulatory Commission ("FERC"). After construction is completed, Nevada Power is permitted to earn a return on these costs as a component of the related assets, as well as recover these costs through depreciation expense over the useful lives of the related assets. Nevada Power's AFUDC rate used during 2024 and 2023 was 7.43% and 6.95%, respectively.

Asset Retirement Obligations

Nevada Power recognizes AROs when it has a legal obligation to perform decommissioning, reclamation or removal activities upon retirement of an asset. Nevada Power's AROs are primarily associated with its generating facilities. The fair value of an ARO liability is recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made, and is added to the carrying amount of the associated asset, which is then depreciated over the remaining useful life of the asset. Subsequent to the initial recognition, the ARO liability is adjusted for any revisions to the original estimate of undiscounted cash flows (with corresponding adjustments to property, plant and equipment, net) and for accretion of the ARO liability due to the passage of time. The difference between the ARO liability, the corresponding ARO asset included in property, plant and equipment, net and amounts recovered in rates to satisfy such liabilities is recorded as a regulatory asset or liability on the Consolidated Balance Sheets. The costs are not recovered in rates until the work has been completed.

Impairment

Nevada Power evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or when the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value and any resulting impairment loss is reflected on the Consolidated Statements of Operations. As substantially all property, plant and equipment was used in regulated businesses, the impacts of regulation are considered when evaluating the carrying value of regulated assets.

Leases

Nevada Power has non-cancelable operating leases primarily for land, generating facilities, vehicles and office equipment and finance leases consisting primarily of transmission assets, generating facilities, office space and vehicles. These leases generally require Nevada Power to pay for insurance, taxes and maintenance applicable to the leased property. Given the capital-intensive nature of the utility industry, it is common for a portion of lease costs to be capitalized when used during construction or maintenance of assets, in which the associated costs will be capitalized with the corresponding asset and depreciated over the remaining life of that asset. Certain leases contain renewal options for varying periods and escalation clauses for adjusting rent to reflect changes in price indices. Nevada Power does not include options in its lease calculations unless there is a triggering event indicating Nevada Power is reasonably certain to exercise the option. Nevada Power's accounting policy is to not recognize right-of-use assets and lease obligations for leases with contract terms of one year or less and not separate lease components from non-lease components and instead account for each separate lease component and the non-lease components associated with a lease as a single lease component. Leases will be evaluated for impairment in line with Accounting Standards Codification ("ASC") Topic 360, "Property, Plant and Equipment" when a triggering event has occurred that might affect the value and use of the assets being leased.

Nevada Power's leases of generating facilities generally are for the long-term purchase of electric energy, also known as power purchase agreements ("PPA"). PPAs are generally signed before or during the early stages of project construction and can yield a lease that has not yet commenced. These agreements are primarily for renewable energy and the payments are considered variable lease payments as they are based on the amount of output.

Nevada Power's operating and right-of-use assets are recorded in other assets and the operating lease liabilities are recorded in current and long-term other liabilities accordingly.

Revenue Recognition

Nevada Power uses a single five-step model to identify and recognize revenue from contracts with customers ("Customer Revenue") upon transfer of control of promised goods or services in an amount that reflects the consideration to which Nevada Power expects to be entitled in exchange for those goods or services. Nevada Power records sales, franchise and excise taxes collected directly from customers and remitted directly to the taxing authorities on a net basis on the Consolidated Statements of Operations.

Substantially all of Nevada Power's Customer Revenue is derived from tariff-based sales arrangements approved by various regulatory commissions. These tariff-based revenues are mainly comprised of energy, transmission and distribution and have performance obligations to deliver energy products and services to customers which are satisfied over time as energy is delivered or services are provided. Other revenue consists primarily of amounts not considered Customer Revenue within ASC 606, "Revenue from Contracts with Customers" and revenue recognized in accordance with ASC 842, "Leases."

Revenue recognized is equal to what Nevada Power has the right to invoice as it corresponds directly with the value to the customer of Nevada Power's performance to date and includes billed and unbilled amounts. As of December 31, 2024 and 2023, trade receivables, net on the Consolidated Balance Sheets relate substantially to Customer Revenue, including unbilled revenue of \$132 million and \$151 million, respectively. Payments for amounts billed are generally due from the customer within 30 days of billing. Rates charged for energy products and services are established by regulators or contractual arrangements that establish the transaction price as well as the allocation of price amongst the separate performance obligations. When preliminary regulated rates are permitted to be billed prior to final approval by the applicable regulator, certain revenue collected may be subject to refund and a liability for estimated refunds is accrued. In addition, Nevada Power has recognized contract assets of \$1 million and \$3 million as of December 31, 2024 and 2023, respectively, due to Nevada Power's performance on certain contracts.

Unamortized Debt Premiums, Discounts and Issuance Costs

Premiums, discounts and financing costs incurred for the issuance of long-term debt are amortized over the term of the related financing using the effective interest method.

Income Taxes

Berkshire Hathaway includes Nevada Power in its consolidated U.S. federal income tax return. Consistent with established regulatory practice, Nevada Power's provision for income taxes has been computed on a stand-alone basis.

Deferred income tax assets and liabilities are based on differences between the financial statement and income tax basis of assets and liabilities using enacted income tax rates expected to be in effect for the year in which the differences are expected to reverse. Changes in deferred income tax assets and liabilities associated with components of other comprehensive income ("OCI") are charged or credited directly to OCI. Changes in deferred income tax assets and liabilities associated with certain property-related basis differences and other various differences that Nevada Power deems probable to be passed on to its customers are charged or credited directly to a regulatory asset or liability and will be included in regulated rates when the temporary differences reverse. Other changes in deferred income tax assets and liabilities are included as a component of income tax expense. Changes in deferred income tax assets and liabilities attributable to changes in enacted income tax rates are charged or credited to income tax expense or a regulatory asset or liability in the period of enactment. Valuation allowances are established when necessary to reduce deferred income tax assets to the amount that is more-likely-than-not to be realized.

Investment tax credits are deferred and amortized over the estimated useful lives of the related properties.

Nevada Power recognizes the tax benefit from an uncertain tax position only if it is more-likely-than-not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the Consolidated Financial Statements from such a position are measured based on the largest benefit that is more-likely-than-not to be realized upon ultimate settlement. Nevada Power's unrecognized tax benefits are primarily included in other long-term liabilities on the Consolidated Balance Sheets. Estimated interest and penalties, if any, related to uncertain tax positions are included as a component of income tax expense (benefit) on the Consolidated Statements of Operations.

Segment Information

Nevada Power currently has one reportable segment, its regulated electric utility operations, which derives its revenue from regulated retail sales of electricity to residential, commercial, and industrial customers and from wholesale sales. Nevada Power's chief operating decision maker ("CODM") is its President and Chief Executive Officer. The CODM uses net income, as reported on the Consolidated Statements of Operations, and generally considers actual results versus historical results, budgets or forecasts, and state regulatory ratemaking results as well as unique risks and opportunities, when making decisions about the allocation of resources and capital. The significant segment expenses regularly provided to the CODM align with the captions presented on the Consolidated Statements of Operations. Nevada Power's segment capital expenditures are reported on the Consolidated Statements of Cash Flows as capital expenditures. Nevada Power's segment assets are reported on the Consolidated Balance Sheets as total assets.

New Accounting Pronouncements

In November 2023, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2023-07, Segment Reporting Topic 280, "Segment Reporting—Improvements to Reportable Segment Disclosures" which allows disclosure of one or more measures of segment profit or loss used by the chief operating decision maker to allocate resources and assess performance. Additionally, the standard requires enhanced disclosures of significant segment expenses and other segment items as well as incremental qualitative disclosures on both an annual and interim basis. This guidance is effective for annual reporting periods beginning after December 15, 2023, and interim reporting periods after December 15, 2024. Early adoption is permitted and retrospective application is required for all periods presented. Nevada Power adopted this guidance for the fiscal year beginning January 1, 2024 under the retrospective method. The adoption did not have a material impact on Nevada Power's Consolidated Financial Statements and disclosures included within the Notes to Consolidated Financial Statements.

In December 2023, the FASB issued ASU No. 2023-09, Income Taxes Topic 740, "Income Tax—Improvements to Income Tax Disclosures" which requires enhanced disclosures, including specific categories and disaggregation of information in the effective tax rate reconciliation, disaggregated information related to income taxes paid, income or loss from continuing operations before income tax expense or benefit, and income tax expense or benefit from continuing operations. This guidance is effective for annual reporting periods beginning after December 15, 2024. Early adoption is permitted and should be applied on a prospective basis, however retrospective application is permitted. Nevada Power is currently evaluating the impact of adopting this guidance on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

In November 2024, the FASB issued ASU No. 2024-03, Income Statement—Reporting Comprehensive Income—Expense Disaggregation Disclosures Subtopic 220-40, "Disaggregation of Income Statement Expenses" which addresses requests from investors for more detailed information about certain expenses and requires disclosure of the amounts of purchases of inventory, employee compensation, depreciation and intangible asset amortization included in each relevant expense caption presented on the income statement. This guidance is effective for annual reporting periods beginning after December 15, 2026 and interim reporting periods beginning after December 15, 2027. Early adoption is permitted and should be applied on a prospective basis, however retrospective application is permitted. Nevada Power is currently evaluating the impact of adopting this guidance on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

(3) Property, Plant and Equipment, Net

Property, plant and equipment, net consists of the following as of December 31 (in millions):

	Depreciable Life	2024	2023
Utility plant:			
Generation	30 - 65 years	\$ 5,369	\$ 4,476
Transmission	55 - 75 years	1,660	1,590
Distribution	24 - 70 years	4,754	4,451
Intangible plant and other	5 - 65 years	900	906
Utility plant		12,683	11,423
Accumulated depreciation and amortization		(4,093)	(3,856)
Utility plant, net		8,590	7,567
Nonregulated, net of accumulated depreciation and amortization	40 years	1	1
		8,591	7,568
Construction work-in-progress		810	1,090
Property, plant and equipment, net		\$ 9,401	\$ 8,658

Almost all of Nevada Power's plant is subject to the ratemaking jurisdiction of the PUCN and the FERC. Nevada Power's depreciation and amortization expense, as authorized by the PUCN, stated as a percentage of the depreciable property balances as of December 31, 2024, 2023 and 2022 was 2.8%, 3.1%, and 3.1%, respectively. Nevada Power is required to file a utility plant depreciation study every six years as a companion filing with the triennial general rate review filings. The most recent study was filed in 2023 and the approved rates were effective January 1, 2024.

Construction work-in-progress is primarily related to the construction of regulated assets.

(4) Jointly Owned Utility Facilities

Under joint facility ownership agreements, Nevada Power, as tenants in common, has undivided interests in jointly owned generation and transmission facilities. Nevada Power accounts for its proportionate share of each facility and each joint owner has provided financing for its share of each facility. Operating costs of each facility are assigned to joint owners based on their percentage of ownership or energy production, depending on the nature of the cost. Operating costs and expenses on the Consolidated Statements of Operations include Nevada Power's share of the expenses of these facilities.

The amounts shown in the table below represent Nevada Power's share in each jointly owned facility included in property, plant and equipment, net as of December 31, 2024 (dollars in millions):

	Nevada Power's Share	Utility Plant	Accumulated Depreciation	Construction Work-in- Progress
ON Line Transmission Line	19	121	31	1
Other transmission facilities	Various	59	29	1
Total		<u>\$ 180</u>	<u>\$ 60</u>	<u>\$ 2</u>

(5) Leases

The following table summarizes Nevada Power's leases recorded on the Consolidated Balance Sheet as of December 31 (in millions):

	2024	2023
Right-of-use assets:		
Operating leases	\$ 5	\$ 7
Finance leases	279	289
Total right-of-use assets	<u>\$ 284</u>	<u>\$ 296</u>
Lease liabilities:		
Operating leases	\$ 7	\$ 9
Finance leases	287	298
Total lease liabilities	<u>\$ 294</u>	<u>\$ 307</u>

The following table summarizes Nevada Power's lease costs for the years ended December 31 (in millions):

	<u>2024</u>	<u>2023</u>	<u>2022</u>
Variable	\$ 270	\$ 264	\$ 369
Operating	2	2	2
Finance:			
Amortization	16	15	14
Interest	24	26	27
Total lease costs	<u>\$ 312</u>	<u>\$ 307</u>	<u>\$ 412</u>
Weighted-average remaining lease term (years):			
Operating leases	2.8	3.7	4.8
Finance leases	27.4	28.2	29.1
Weighted-average discount rate:			
Operating leases	4.5 %	4.5 %	4.5 %
Finance leases	8.6 %	8.6 %	8.6 %

The following table summarizes Nevada Power's supplemental cash flow information relating to leases for the years ended December 31 (in millions):

	<u>2024</u>	<u>2023</u>	<u>2022</u>
Cash paid for amounts included in the measurement of lease liabilities:			
Operating cash flows from operating leases	\$ (3)	\$ (3)	\$ (3)
Operating cash flows from finance leases	(25)	(26)	(28)
Financing cash flows from finance leases	(20)	(18)	(17)
Right-of-use assets obtained in exchange for lease liabilities:			
Operating leases	\$ —	\$ 1	\$ —
Finance leases	9	4	3

Nevada Power has the following remaining lease commitments as of December 31, 2024 (in millions):

	Operating	Finance	Total
2025	\$ 3	\$ 45	\$ 48
2026	3	45	48
2027	2	44	46
2028	—	40	40
2029	—	25	25
Thereafter	—	360	360
Total undiscounted lease payments	8	559	567
Less - amounts representing interest	(1)	(272)	(273)
Lease liabilities	<u>\$ 7</u>	<u>\$ 287</u>	<u>\$ 294</u>

Operating and Finance Lease Obligations

Nevada Power's lease obligation primarily consists of a transmission line, One Nevada Transmission Line ("ON Line"), which was placed in-service on December 31, 2013. Nevada Power and Sierra Pacific, collectively the ("Nevada Utilities"), entered into a long-term transmission use agreement, in which the Nevada Utilities have a 25% interest and Great Basin Transmission South, LLC has a 75% interest. The Nevada Utilities' share of the long-term transmission use agreement and ownership interest is split at 75% for Nevada Power and 25% for Sierra Pacific. The term of the lease is 41 years with the agreement ending December 31, 2054. Total ON Line finance lease obligations of \$253 million and \$264 million were included on the Consolidated Balance Sheets as of December 31, 2024 and 2023, respectively. See Note 2 for further discussion of Nevada Power's other lease obligations.

(6) Regulatory Matters

Regulatory Assets

Regulatory assets represent costs that are expected to be recovered in future rates. Nevada Power's regulatory assets reflected on the Consolidated Balance Sheets consist of the following as of December 31 (in millions):

	Weighted Average Remaining Life	2024	2023
Deferred energy costs	1 year	\$ 110	\$ 575
Merger costs from 1999 merger	20 years	95	100
Asset retirement obligations	7 years	66	69
Unrealized loss on regulated derivative contracts	1 year	57	68
Decommissioning costs	3 years	57	56
Deferred operating costs	18 years	39	41
ON Line deferrals	28 years	38	40
Legacy meters	8 years	30	34
Other	Various	91	102
Total regulatory assets		<u>\$ 583</u>	<u>\$ 1,085</u>
Reflected as:			
Current assets		\$ 124	\$ 586
Noncurrent assets		459	499
Total regulatory assets		<u>\$ 583</u>	<u>\$ 1,085</u>

Nevada Power had regulatory assets not earning a return on investment of \$313 million and \$299 million as of December 31, 2024 and 2023, respectively. The regulatory assets not earning a return on investment primarily consist of merger costs from the 1999 merger, AROs, unrealized losses on regulated derivative contracts, deferred operating costs, losses on reacquired debt and a portion of the employee benefit plans.

Regulatory Liabilities

Regulatory liabilities represent amounts that are expected to be returned to customers in future periods. Nevada Power's regulatory liabilities reflected on the Consolidated Balance Sheets consist of the following as of December 31 (in millions):

	Weighted Average Remaining Life	2024	2023
Deferred income taxes ⁽¹⁾	Various	\$ 510	\$ 525
Cost of removal ⁽²⁾	37 years	399	368
Earning sharing mechanism	4 years	77	115
Other	Various	52	52
Total regulatory liabilities		\$ 1,038	\$ 1,060
Reflected as:			
Current liabilities		\$ 41	\$ 43
Noncurrent liabilities		997	1,017
Total regulatory liabilities		\$ 1,038	\$ 1,060

(1) Amounts primarily represent income tax liabilities related to the federal tax rate change from 35% to 21% that are probable to be passed on to customers, offset by income tax benefits related to accelerated tax depreciation and certain property-related basis differences that were previously passed on to customers and will be included in regulated rates when the temporary differences reverse.

(2) Amounts represent estimated costs, as accrued through depreciation rates and exclusive of ARO liabilities, of removing regulated property, plant and equipment in accordance with accepted regulatory practices.

Deferred Energy

Nevada statutes permit regulated utilities to adopt deferred energy accounting procedures. The intent of these procedures is to ease the effect on customers of fluctuations in the cost of purchased natural gas, fuel and electricity and are subject to annual prudence review by the PUCN. Under deferred energy accounting, to the extent actual fuel and purchased power costs exceed fuel and purchased power costs recoverable through current rates that excess is not recorded as a current expense on the Consolidated Statements of Operations but rather is deferred and recorded as a regulatory asset on the Consolidated Balance Sheets and would be included in the regulatory assets table above as deferred energy costs. Conversely, a regulatory liability is recorded to the extent fuel and purchased power costs recoverable through current rates exceed actual fuel and purchased power costs and is included in the regulatory liabilities table above as deferred energy costs. These excess amounts are reflected in quarterly adjustments to rates and recorded as cost of fuel, energy and capacity in future time periods.

Regulatory Rate Review

In June 2023, Nevada Power filed a regulatory rate review with the PUCN that requested an annual revenue increase of \$93 million, or 3.3%. In addition, a filing was made to revise depreciation rates based on a study, the results of which are reflected in the proposed revenue requirement. In August 2023, Nevada Power filed an updated certification filing that requested an annual revenue increase of \$96 million, or 3.3%. Parties to the review filed testimony and evidence in August and September 2023. Hearings in the cost of capital, revenue requirement and rate design phases were held in October and November 2023. In December 2023, the PUCN issued an order approving an increase in base rates of \$37 million, effective January 1, 2024, reflecting a reduction in Nevada Power's requested rate of return and updated depreciation and amortization rates for its electric operations. In January 2024, Nevada Power filed a petition for reconsideration and clarification of the order. In February of 2024, the PUCN issued a final order approving in part and denying in part the petition for reconsideration with the final order being materially in line with the original order.

In February 2025, Nevada Power filed an electric regulatory rate review with the PUCN that requested an annual revenue increase of \$215 million, or 9.0%. An order is expected by the third quarter of 2025 and, if approved, rates are proposed to be effective October 1, 2025.

Wildfire Self-Insurance Policy Filing

In January 2025, Nevada Power filed an application for approval of the establishment and associated cost recovery of a Wildfire Self-Insurance Policy. In the application, Nevada Power request first, that the PUCN issue an order determining that it is reasonable and prudent for the Nevada Utilities to establish a \$500 million wildfire self-insurance policy (the "Policy") in order to have additional wildfire liability insurance in place in the event that a catastrophic wildfire in Nevada is alleged to be caused or exacerbated by utility equipment. The Policy would provide \$500 million in additional coverage for the Nevada Utilities for third-party claims, and it would be in excess to the commercial wildfire liability insurance the Nevada Utilities currently possess. Second, the application requests approval for the collection of the costs for the Policy in rates over a ten-year period. An order is expected in 2025.

(7) Short-term Debt and Credit Facilities

Nevada Power has a \$600 million secured credit facility expiring in June 2027 with an unlimited number of maturity extension options, subject to lender consent. The credit facility, which is for general corporate purposes and provide for the issuance of letters of credit, has a variable interest rate based on the Secured Overnight Financing Rate ("SOFR") or a base rate, at Nevada Power's option, plus a spread that varies based on Nevada Power's credit ratings for its senior secured long-term debt securities. As of December 31, 2024 and 2023, Nevada Power had no borrowings outstanding under the credit facility. Amounts due under Nevada Power's credit facility are collateralized by Nevada Power's general and refunding mortgage bonds. The credit facility requires Nevada Power's ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.65 to 1.0 as of the last day of each quarter.

As of December 31, 2024 and 2023, Nevada Power had \$50 million, respectively, of letter of credit capacity under its \$600 million secured credit facility, of which no amount was outstanding.

(8) Long-term Debt

Nevada Power's long-term debt consists of the following, including unamortized premiums, discounts and debt issuance costs, as of December 31 (dollars in millions):

	Par Value	2024	2023
General and refunding mortgage securities:			
3.70% Series CC, due 2029	\$ 500	\$ 498	\$ 498
2.40% Series DD, due 2030	425	423	423
6.65% Series N, due 2036	367	361	360
6.75% Series R, due 2037	349	347	346
5.375% Series X, due 2040	250	248	248
5.45% Series Y, due 2041	250	240	240
3.125% Series EE, due 2050	300	298	298
5.90% Series GG, due 2053	400	394	394
6.00% Series 2023A, due 2054	500	495	494
Tax-exempt refunding revenue bond obligations:			
Fixed-rate series:			
4.125% Pollution Control Bonds Series 2017A, due 2032 ⁽¹⁾	40	39	39
3.75% Pollution Control Bonds Series 2017, due 2036 ⁽¹⁾	40	39	39
3.75% Pollution Control Bonds Series 2017B, due 2039 ⁽¹⁾	13	13	13
Total long-term debt	\$ 3,434	\$ 3,395	\$ 3,392
Reflected as:			
Total long-term debt		\$ 3,395	\$ 3,392

(1) Subject to mandatory purchase by Nevada Power in March 2026 at which date the interest rate may be adjusted.

In February 2025, Nevada Power issued \$300 million of its 6.25% Fixed-to-Fixed Reset Rate Junior Subordinated Notes due 2055. Nevada Power will pay interest on the Notes at a rate of 6.25% through May 2030, subject to a reset every 5 years. Nevada Power intends to use the net proceeds from the sale of the notes to fund capital expenditures and for general corporate purposes.

Annual Payment on Long-Term Debt

The annual repayments of long-term debt for the years beginning January 1, 2025 and thereafter, are as follows (in millions):

2029 and thereafter	\$ 3,434
Total	3,434
Unamortized premium, discount and debt issuance cost	(39)
Total	<u>\$ 3,395</u>

The issuance of General and Refunding Mortgage Securities by Nevada Power is subject to PUCN approval and is limited by available property and other provisions of the mortgage indentures. As of December 31, 2024, approximately \$11.5 billion (based on original cost) of Nevada Power's property was subject to the liens of the mortgages.

(9) Income Taxes

Income tax expense consists of the following for the years ended December 31 (in millions):

	<u>2024</u>	<u>2023</u>	<u>2022</u>
Current – Federal	\$ 65	\$ (4)	\$ (13)
Deferred – Federal	(49)	(74)	49
Investment tax credits	41	100	—
Total income tax expense	<u>\$ 57</u>	<u>\$ 22</u>	<u>\$ 36</u>

A reconciliation of the federal statutory income tax rate to the effective income tax rate applicable to income before income tax expense is as follows for the years ended December 31:

	<u>2024</u>	<u>2023</u>	<u>2022</u>
Federal statutory income tax rate	21 %	21 %	21 %
Effects of ratemaking	(4)	(13)	(11)
Income tax credits	(3)	—	—
Other	—	—	1
Effective income tax rate	<u>14 %</u>	<u>8 %</u>	<u>11 %</u>

Effects of ratemaking is primarily attributable to the recognition of excess deferred income taxes related to the federal tax rate change from 35% to 21% pursuant to an order issued by the PUCN effective January 1, 2021.

Income tax credits relate to production tax credits ("PTCs") and investment tax credits ("ITCs") from Nevada Power's solar-powered generating facilities and energy storage properties. Federal renewable electricity PTCs are earned as energy from qualifying solar-powered generating facilities is produced and sold and are based on a per-kilowatt hour rate pursuant to the applicable federal income tax law. Solar-powered generating facilities are eligible for the credits for 10 years from the date the qualifying generating facilities are placed in-service. Federal renewable electricity ITCs are tax credits that reduce the income tax liability by a percentage of the cost from certain qualifying solar-powered generating facilities or energy storage properties over their useful lives. The percentage of the credit varies depending on attributes of the project up to a maximum of 50 percent. PTCs recognized for the for the years ended December 31, 2024, 2023 and 2022 totaled \$8 million, \$— million and \$— million, respectively. ITCs recognized for the years ended December 31, 2024, 2023 and 2022 totaled \$7 million, \$— million and \$— million, respectively.

The net deferred income tax liability consists of the following as of December 31 (in millions):

	2024	2023
Deferred income tax assets:		
Regulatory liabilities	\$ 201	\$ 195
Operating and finance leases	62	66
Customer advances	44	38
Unamortized contract value	12	14
Other	8	9
Total deferred income tax assets	327	322
Deferred income tax liabilities:		
Property-related items	(884)	(828)
Regulatory assets	(163)	(245)
Operating and finance leases	(59)	(62)
Other	(23)	(23)
Total deferred income tax liabilities	(1,129)	(1,158)
Net deferred income tax liability	\$ (802)	\$ (836)

The U.S. Internal Revenue Service has closed or effectively settled its examination of Nevada Power's income tax return through the short year ended December 31, 2013. The closure of examinations, or the expiration of the statute of limitations, may not preclude the U.S. Internal Revenue Service from adjusting the federal net operating loss carryforward utilized in a year for which the statute of limitations is not closed.

(10) Employee Benefit Plans

Nevada Power is a participant in benefit plans sponsored by NV Energy. The NV Energy Retirement Plan includes a qualified pension plan ("Qualified Pension Plan") and a supplemental executive retirement plan and a restoration plan (collectively, "Non-Qualified Pension Plans") that provide pension benefits for eligible employees. The NV Energy Comprehensive Welfare Benefit and Cafeteria Plan provides certain postretirement health care and life insurance benefits for eligible retirees ("Other Postretirement Plans") on behalf of Nevada Power. Nevada Power did not make any contributions to the Qualified Pension Plan for the years ended December 31, 2024, 2023 and 2022. Nevada Power contributed \$1 million to the Non-Qualified Pension Plans for the years ended December 31, 2024, 2023 and 2022. Nevada Power did not make any contributions to the Other Postretirement Plans for the years ended December 31, 2024, 2023 and 2022. Amounts attributable to Nevada Power were allocated from NV Energy based upon the current, or in the case of retirees, previous, employment location. Offsetting regulatory assets and liabilities have been recorded related to the amounts not yet recognized as a component of net periodic benefit costs that will be included in regulated rates. Net periodic benefit costs not included in regulated rates are included in accumulated other comprehensive loss, net.

Amounts receivable from (payable to) NV Energy are included on the Consolidated Balance Sheets and consist of the following as of December 31 (in millions):

	2024	2023
Qualified Pension Plan -		
Other non-current assets	\$ 39	\$ 38
Non-Qualified Pension Plans:		
Other current liabilities	(1)	(1)
Other long-term liabilities	(6)	(6)
Other Postretirement Plans -		
Other non-current assets	19	10

(11) Asset Retirement Obligations

Nevada Power estimates its ARO liabilities based upon detailed engineering calculations of the amount and timing of the future cash spending for a third party to perform the required work. Spending estimates are escalated for inflation and then discounted at a credit-adjusted, risk-free rate. Changes in estimates could occur for a number of reasons, including changes in laws and regulations, plan revisions, inflation and changes in the amount and timing of the expected work.

Nevada Power does not recognize liabilities for AROs for which the fair value cannot be reasonably estimated. Due to the indeterminate removal date, the fair value of the associated liabilities on certain generation, transmission, distribution and other assets cannot currently be estimated, and no amounts are recognized on the Consolidated Financial Statements other than those included in the cost of removal regulatory liability established via approved depreciation rates in accordance with accepted regulatory practices. These accruals totaled \$399 million and \$368 million as of December 31, 2024 and 2023, respectively.

The following table presents Nevada Power's ARO liabilities by asset type as of December 31 (in millions):

	<u>2024</u>	<u>2023</u>
Waste water remediation	\$ 31	\$ 33
Evaporative ponds and dry ash landfills	12	12
Solar-powered generating facilities	6	6
Other	8	11
Total asset retirement obligations	<u>\$ 57</u>	<u>\$ 62</u>

The following table reconciles the beginning and ending balances of Nevada Power's ARO liabilities for the years ended December 31 (in millions):

	<u>2024</u>	<u>2023</u>
Beginning balance	\$ 62	\$ 59
Change in estimated costs	(3)	6
Additions	3	3
Retirements	(8)	(9)
Accretion	3	3
Ending balance	<u>\$ 57</u>	<u>\$ 62</u>
Reflected as:		
Other current liabilities	\$ 5	\$ 9
Other long-term liabilities	52	53
	<u>\$ 57</u>	<u>\$ 62</u>

In 2008, Nevada Power signed an administrative order of consent as owner and operator of Reid Gardner Generating Station Unit Nos. 1, 2 and 3 and as co-owner and operating agent of Unit No. 4. Based on the administrative order of consent, Nevada Power recorded estimated AROs and capital remediation costs. However, actual costs of work under the administrative order of consent may vary significantly once the scope of work is defined and additional site characterization has been completed. In connection with the termination of the co-ownership arrangement, effective October 22, 2013, between Nevada Power and California Department of Water Resources ("CDWR") for the Reid Gardner Generating Station Unit No. 4, Nevada Power and CDWR entered into a cost-sharing agreement that sets forth how the parties will jointly share in costs associated with all investigation, characterization and, if necessary, remedial activities as required under the administrative order of consent.

Certain of Nevada Power's decommissioning and reclamation obligations relate to jointly-owned facilities, and as such, Nevada Power is committed to pay a proportionate share of the decommissioning or reclamation costs. In the event of a default by any of the other joint participants, the respective subsidiary may be obligated to absorb, directly or by paying additional sums to the entity, a proportionate share of the defaulting party's liability. Management has identified legal obligations to retire generation plant assets specified in land leases for Nevada Power's jointly-owned Navajo Generating Station, retired in November 2019, and the Higgins Generating Station. Provisions of the lease require the lessees to remove the facilities upon request of the lessors at the expiration of the leases. Nevada Power's estimated share of the decommissioning and reclamation obligations are primarily recorded as ARO liabilities in other long-term liabilities on the Consolidated Balance Sheets.

In May 2024, the United States Environmental Protection Agency published its final rule on legacy coal combustion residuals ("CCR") surface impoundments and CCR management units ("CCRMUs") in the Federal Register. CCRMUs include CCR surface impoundments and landfills closed before October 19, 2015 and inactive CCR landfills. The final rule contains three main components: (1) a definition for legacy CCR surface impoundments, which are inactive surface impoundments at inactive generating facilities that must adhere to the same regulations as inactive CCR impoundments at active generating facilities, barring location restrictions and liner design criteria, with customized compliance deadlines; (2) groundwater monitoring, corrective action, closure, and post closure care requirements for CCRMUs, which may be located at active generating facilities and inactive generating facilities with a legacy CCR surface impoundment; and (3) the owners and operators of inactive generating facilities must identify the presence of legacy CCR surface impoundments and comply with all rule requirements for surface impoundments; and the owners and operators of active generating facilities and inactive generating facilities with a legacy CCR surface impoundment must prepare Facility Evaluation Reports ("FERs") that identify and describe the CCRMUs and determine whether closure is required. In a manner consistent with existing CCR rules, owners and operators must publish FERs on their CCR websites in two parts, within 15 months (Part 1) and 27 months (Part 2) of the final rule's effective date in November 2024. Nevada Power is currently evaluating the final rule and does not anticipate identifying any legacy surface impoundments, but does anticipate identifying CCRMUs subject to the rule. Due to the number of site investigations warranted by this rule and the nature of engineering and other studies required at each site, Nevada Power is unable to reasonably estimate the potential impact, which may be material, to its asset retirement obligations.

(12) Risk Management and Hedging Activities

Nevada Power is exposed to the impact of market fluctuations in commodity prices and interest rates. Nevada Power is principally exposed to electricity and natural gas market fluctuations primarily through Nevada Power's obligation to serve retail customer load in its regulated service territory. Nevada Power's load and generating facilities represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel required to generate electricity and wholesale electricity that is purchased and sold. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather, market liquidity, generating facility availability, customer usage, storage, and transmission and transportation constraints. The actual cost of fuel and purchased power is recoverable through the deferred energy mechanism. Interest rate risk exists on variable-rate debt and future debt issuances. Nevada Power does not engage in proprietary trading activities.

Nevada Power has established a risk management process that is designed to identify, assess, manage and report on each of the various types of risk involved in its business. To mitigate a portion of its commodity price risk, Nevada Power uses commodity derivative contracts, which may include forwards, futures, options, swaps and other agreements, to effectively secure future supply or sell future production generally at fixed prices. Nevada Power manages its interest rate risk by limiting its exposure to variable interest rates primarily through the issuance of fixed-rate long-term debt and by monitoring market changes in interest rates. Additionally, Nevada Power may from time to time enter into interest rate derivative contracts, such as interest rate swaps or locks, to mitigate Nevada Power's exposure to interest rate risk. Nevada Power does not hedge all of its commodity price and interest rate risks, thereby exposing the unhedged portion to changes in market prices.

There have been no significant changes in Nevada Power's accounting policies related to derivatives. Refer to Notes 2 and 13 for additional information on derivative contracts.

The following table, which excludes contracts that have been designated as normal under the normal purchases and normal sales exception afforded by GAAP, summarizes the fair value of Nevada Power's derivative contracts, on a gross basis, and reconciles those amounts presented on a net basis on the Consolidated Balance Sheets (in millions):

	Other Current Assets	Derivative Contracts - Current Liabilities	Other Long-term Liabilities	Total
As of December 31, 2024:				
Not designated as hedging contracts ⁽¹⁾ -				
Commodity liabilities	\$ —	\$ (53)	\$ (4)	\$ (57)
As of December 31, 2023:				
Not designated as hedging contracts ⁽¹⁾ -				
Commodity liabilities	\$ —	\$ (62)	\$ (6)	\$ (68)

- (1) Nevada Power's commodity derivatives not designated as hedging contracts are included in regulated rates. As of December 31, 2024 and 2023, a regulatory asset of \$57 million and \$68 million, respectively, was recorded related to the net derivative liability of \$57 million and \$68 million, respectively.

Derivative Contract Volumes

The following table summarizes the net notional amounts of outstanding commodity derivative contracts with fixed price terms that comprise the mark-to-market values as of December 31 (in millions):

	Unit of Measure	2024	2023
Electricity purchases	Megawatt hours	2	1
Natural gas purchases	Decatherms	127	132

Credit Risk

Nevada Power is exposed to counterparty credit risk associated with wholesale energy supply and marketing activities with other utilities, energy marketing companies, financial institutions and other market participants. Credit risk may be concentrated to the extent Nevada Power's counterparties have similar economic, industry or other characteristics and due to direct and indirect relationships among the counterparties. Before entering into a transaction, Nevada Power analyzes the financial condition of each significant wholesale counterparty, establishes limits on the amount of unsecured credit to be extended to each counterparty and evaluates the appropriateness of unsecured credit limits on an ongoing basis. To further mitigate wholesale counterparty credit risk, Nevada Power enters into netting and collateral arrangements that may include margining and cross-product netting agreements and obtain third-party guarantees, letters of credit and cash deposits. If required, Nevada Power exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

Collateral and Contingent Features

In accordance with industry practice, certain wholesale agreements, including derivative contracts, contain credit support provisions that in part base certain collateral requirements on credit ratings for senior unsecured debt as reported by one or more of the recognized credit rating agencies. These agreements may either specifically provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed specified rating-dependent threshold levels "credit-risk-related contingent features") or provide the right for counterparties to demand "adequate assurance" if there is a material adverse change in Nevada Power's creditworthiness. These rights can vary by contract and by counterparty. As of December 31, 2024, Nevada Power's credit ratings for its senior secured debt and its issuer credit ratings for senior unsecured debt from the recognized credit rating agencies were investment grade.

The aggregate fair value of Nevada Power's derivative contracts in liability positions with specific credit-risk-related contingent features totaled \$13 million and \$7 million as of December 31, 2024 and 2023, respectively, which represents the amount of collateral to be posted if all credit risk related contingent features for derivative contracts in liability positions had been triggered. Nevada Power's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation or other factors.

(13) Fair Value Measurements

The carrying value of Nevada Power's cash, certain cash equivalents, receivables, payables, accrued liabilities and short-term borrowings approximates fair value because of the short-term maturity of these instruments. Nevada Power has various financial assets and liabilities that are measured at fair value on the Consolidated Balance Sheets using inputs from the three levels of the fair value hierarchy. A financial asset or liability classification within the hierarchy is determined based on the lowest level input that is significant to the fair value measurement. The three levels are as follows:

- Level 1 - Inputs are unadjusted quoted prices in active markets for identical assets or liabilities that Nevada Power has the ability to access at the measurement date.
- Level 2 - Inputs include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived principally from or corroborated by observable market data by correlation or other means (market corroborated inputs).
- Level 3 - Unobservable inputs reflect Nevada Power's judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. Nevada Power develops these inputs based on the best information available, including its own data.

The following table presents Nevada Power's financial assets and liabilities recognized on the Consolidated Balance Sheets and measured at fair value on a recurring basis (in millions):

	Input Levels for Fair Value Measurements			
	Level 1	Level 2	Level 3	Total
As of December 31, 2024:				
Assets:				
Money market mutual funds	\$ 15	\$ —	\$ —	\$ 15
Investment funds	4	—	—	4
	<u>\$ 19</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 19</u>
Liabilities - commodity derivatives	<u>\$ —</u>	<u>\$ —</u>	<u>\$ (57)</u>	<u>\$ (57)</u>
As of December 31, 2023:				
Assets:				
Money market mutual funds	\$ 10	\$ —	\$ —	\$ 10
Investment funds	4	—	—	4
	<u>\$ 14</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 14</u>
Liabilities - commodity derivatives	\$ —	\$ —	\$ (68)	\$ (68)

Nevada Power's investments in money market mutual funds and investment funds are accounted for as available-for-sale securities and are stated at fair value. When available, a readily observable quoted market price or net asset value of an identical security in an active market is used to record the fair value.

Derivative contracts are recorded on the Consolidated Balance Sheets as either assets or liabilities and are stated at estimated fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by GAAP. When available, the fair value of derivative contracts is estimated using unadjusted quoted prices for identical contracts in the market in which Nevada Power transacts. When quoted prices for identical contracts are not available, Nevada Power uses forward price curves. Forward price curves represent Nevada Power's estimates of the prices at which a buyer or seller could contract today for delivery or settlement at future dates. Nevada Power bases its forward price curves upon internally developed models, with internal and external fundamental data inputs. Market price quotations for certain electricity and natural gas trading hubs are not as readily obtainable due to markets that are not active. Given that limited market data exists for these contracts, Nevada Power uses forward price curves derived from internal models based on perceived pricing relationships to major trading hubs that are based on unobservable inputs. The model incorporates a mid-market pricing convention (the mid-point price between bid and ask prices) as a practical expedient for valuing its assets and liabilities measured and reported at fair value. The determination of the fair value for derivative contracts not only includes counterparty risk, but also the impact of Nevada Power's nonperformance risk on its liabilities, which as of December 31, 2024, had an immaterial impact to the fair value of its derivative contracts. As such, Nevada Power considers its derivative contracts to be valued using Level 3 inputs.

The following table reconciles the beginning and ending balances of Nevada Power's net commodity derivative assets and liabilities measured at fair value on a recurring basis using significant Level 3 inputs for the years ended December 31 (in millions):

	2024	2023	2022
Beginning balance	\$ (68)	\$ (52)	\$ (113)
Changes in fair value recognized in regulatory assets or liabilities	(95)	(166)	(68)
Settlements	106	150	129
Ending balance	<u>\$ (57)</u>	<u>\$ (68)</u>	<u>\$ (52)</u>

Nevada Power's long-term debt is carried at cost on the Consolidated Balance Sheets. The fair value of Nevada Power's long-term debt is a Level 2 fair value measurement and has been estimated based upon quoted market prices, where available, or at the present value of future cash flows discounted at rates consistent with comparable maturities with similar credit risks. The following table presents the carrying value and estimated fair value of Nevada Power's long-term debt as of December 31 (in millions):

	2024		2023	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	\$ 3,395	\$ 3,299	\$ 3,392	\$ 3,417

(14) Commitments and Contingencies

Commitments

Nevada Power has the following firm commitments that are not reflected on the Consolidated Balance Sheet. Minimum payments as of December 31, 2024 are as follows (in millions):

	2025	2026	2027	2028	2029	2030 and Thereafter	Total
Contract type:							
Purchased electricity contracts - commercially operable	\$ 407	\$ 410	\$ 411	\$ 388	\$ 391	\$ 4,556	\$ 6,563
Purchased electricity contracts - non-commercially operable	—	4	83	261	261	5,011	5,620
Fuel contracts	55	54	53	47	45	79	333
Construction commitments	667	597	387	153	32	27	1,863
Transmission	12	28	11	7	5	42	105
Easements	4	4	4	4	2	32	50
Maintenance, service and other contracts	16	27	31	15	1	—	90
Total commitments	<u>\$ 1,161</u>	<u>\$ 1,124</u>	<u>\$ 980</u>	<u>\$ 875</u>	<u>\$ 737</u>	<u>\$ 9,747</u>	<u>\$ 14,624</u>

Purchased Electricity Contracts - Commercially Operable

Nevada Power has several contracts for long-term purchase of electric energy which have been approved by the PUCN. The expiration of these contracts range from 2026 to 2067. Purchased power includes estimated payments for contracts which meet the definition of a lease and payments are based on the amount of energy expected to be generated. See Note 5 for further discussion of Nevada Power's lease commitments.

Purchased Electricity Contracts - Non-Commercially Operable

Nevada Power has several contracts for long-term purchase of electric energy in which the facility remains under development. Amounts represent the estimated payments under renewable energy power purchase contracts, which have been approved by the PUCN and are contingent upon the developers obtaining commercial operation and their ability to deliver power.

Fuel Contracts

Nevada Power's gas transportation contracts expire from 2024 to 2039.

Construction Commitments

Nevada Power's construction commitments included in the table above relate to firm commitments and include costs associated with a 400-MW solar photovoltaic facility with an additional 400-MWs of co-located battery storage that is being developed in Churchill County, Nevada, with ownership share approved by the PUCN of 10% Nevada Power and 90% Sierra Pacific and the Greenlink Nevada transmission expansion program that is being developed in western and northern Nevada and certain other generation plant projects.

Transmission

Nevada Power has contracts for the right to transmit electricity over other entities' transmission lines to facilitate delivery to Nevada Power's customers.

Easements

Nevada Power has non-cancelable easements for land. Operations and maintenance expense on non-cancelable easements totaled \$4 million for the years ended December 31, 2024, 2023 and 2022.

Maintenance, Service and Other Contracts

Nevada Power has long-term service agreements for the performance of maintenance on generation units. Obligation amounts are based on estimated usage. The estimated expiration of these service agreements range from 2024 to 2029.

Environmental Laws and Regulations

Nevada Power is subject to federal, state and local laws and regulations regarding air quality, climate change, emissions performance standards, water quality, coal ash disposal and other environmental matters that have the potential to impact its current and future operations. Nevada Power believes it is in material compliance with all applicable laws and regulations.

Legal Matters

Nevada Power is party to a variety of legal actions arising out of the normal course of business. Nevada Power does not believe that such normal and routine litigation will have a material impact on its consolidated financial results.

(15) Revenues from Contracts with Customers

The following table summarizes Nevada Power's Customer Revenue by customer class for the years ended December 31 (in millions):

	<u>2024</u>	<u>2023</u>	<u>2022</u>
Customer Revenue:			
Retail:			
Residential	\$ 1,602	\$ 1,633	\$ 1,440
Commercial	572	647	525
Industrial	608	689	528
Other	6	23	14
Total fully bundled	2,788	2,992	2,507
Distribution-only service	15	14	20
Total retail	2,803	3,006	2,527
Wholesale, transmission and other	66	63	82
Total Customer Revenue	2,869	3,069	2,609
Other revenue	4	19	21
Total operating revenue	<u>\$ 2,873</u>	<u>\$ 3,088</u>	<u>\$ 2,630</u>

(16) Supplemental Cash Flow Disclosures

The summary of supplemental cash flow disclosures as of and for the years ended December 31 is as follows (in millions):

	<u>2024</u>	<u>2023</u>	<u>2022</u>
Supplemental disclosure of cash flow information:			
Interest paid, net of amounts capitalized	\$ 173	\$ 159	\$ 121
Income taxes (refunded) paid	\$ 177	\$ (52)	\$ (29)
Supplemental disclosure of non-cash investing and financing transactions:			
Accruals related to property, plant and equipment additions	\$ 169	\$ 230	\$ 98

(17) Related Party Transactions

Nevada Power has an intercompany administrative services agreement with BHE and its subsidiaries. Amounts charged to Nevada Power under this agreement, either directly or through NV Energy, totaled \$82 million, \$55 million and \$46 million for the years ended December 31, 2024, 2023 and 2022, respectively. Amounts charged to Nevada Power in 2024 and 2023 primarily relate to information technology projects billed at a consolidated level and passed through to affiliates.

Kern River Gas Transmission Company, an indirect subsidiary of BHE, provided natural gas transportation and other services to Nevada Power of \$51 million, \$50 million, \$49 million for the years ended December 31, 2024, 2023 and 2022, respectively. As of December 31, 2024 and 2023, Nevada Power's Consolidated Balance Sheets included amounts due to Kern River Gas Transmission Company of \$4 million.

Nevada Power provided electricity and other services to PacifiCorp, an indirect subsidiary of BHE, of \$2 million, \$1 million and \$4 million for the years ended December 31, 2024, 2023 and 2022, respectively. There were no receivables associated with these services as of December 31, 2024 and 2023.

Nevada Power provided electricity to Sierra Pacific of \$188 million, \$230 million and \$362 million for the years ended December 31, 2024, 2023 and 2022, respectively. Receivables associated with these transactions were \$7 million and \$10 million as of December 31, 2024 and 2023, respectively. Nevada Power purchased electricity from Sierra Pacific of \$29 million, \$70 million and \$86 million for the years ended December 31, 2024, 2023 and 2022, respectively. Payables associated with these transactions were \$1 million as of December 31, 2024 and 2023.

Nevada Power incurs intercompany administrative and shared facility costs with NV Energy and Sierra Pacific. These transactions are governed by an intercompany service agreement and are priced at cost. Nevada Power provided services to NV Energy of \$8 million, \$4 million and \$3 million for each of the years ending December 31, 2024, 2023 and 2022. NV Energy provided services to Nevada Power of \$8 million, \$9 million and \$9 million for the years ending December 31, 2024, 2023 and 2022, respectively. Nevada Power provided services to Sierra Pacific of \$31 million, \$28 million and \$25 million for the years ended December 31, 2024, 2023 and 2022, respectively. Sierra Pacific provided services to Nevada Power of \$19 million, \$19 million and \$16 million for the years ended December 31, 2024, 2023 and 2022, respectively. As of December 31, 2024 and 2023, Nevada Power's Consolidated Balance Sheets included amounts due to NV Energy of \$51 million and \$82 million, respectively. There were no receivables due from NV Energy as of December 31, 2024 and 2023. As of December 31, 2024 and 2023, Nevada Power's Consolidated Balance Sheets included no receivables due from Sierra Pacific. There were \$65 million and \$20 million payables due to Sierra Pacific as of December 31, 2024 and 2023.

Nevada Power is party to a tax-sharing agreement and is part of the Berkshire Hathaway consolidated U.S. federal income tax return. Federal income taxes payable to BHE were \$82 million as of December 31, 2024 and federal income taxes receivable from BHE were \$31 million as of December 31, 2023. Nevada Power made cash payments for federal income tax to BHE of \$177 million for the year ended December 31, 2024 and received cash refunds from BHE of \$52 million and \$29 million for federal income taxes for the years ended December 31, 2023 and 2022, respectively.

Certain disbursements for accounts payable and payroll are made by NV Energy on behalf of Nevada Power and reimbursed automatically when settled by the bank. These amounts are recorded as accounts payable at the time of disbursement.

Sierra Pacific Power Company and its subsidiaries
Consolidated Financial Section

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

The following is management's discussion and analysis of certain significant factors that have affected the consolidated financial condition and results of operations of Sierra Pacific during the periods included herein. Explanations include management's best estimate of the impact of weather, customer growth, usage trends and other factors. This discussion should be read in conjunction with Sierra Pacific's historical Consolidated Financial Statements and Notes to Consolidated Financial Statements in Item 8 of this Form 10-K. Sierra Pacific's actual results in the future could differ significantly from the historical results.

Results of Operations

Overview

Net income for the year ended December 31, 2024 was \$85 million, a decrease of \$32 million, or 27%, compared to 2023, primarily due to increased operations and maintenance expense, higher interest expense and lower interest and dividend income. These items were partially offset by higher electric utility margin, higher allowance for equity funds, lower income tax expense and favorable other, net from lower pension expense. Electric utility margin increased primarily due to higher retail rates from the 2024 regulatory rate review with new rates effective October 2024 and higher retail customer volumes, partially offset by lower transmission and wholesale revenue. Electric retail customer volumes, including distribution only service customers, increased 3.9% primarily due to the favorable impact of weather and an increase in the average number of customers. Energy generated increased 8% for 2024 compared to 2023 primarily due to higher natural gas- and coal-fueled generation. Wholesale electricity sales volumes increased 10% and purchased electricity volumes decreased 17%.

Net income for the year ended December 31, 2023 was \$117 million, a decrease of \$1 million, or 1%, compared to 2022, primarily due to higher depreciation and amortization expense, higher operations and maintenance expense and higher interest expense. These items were partially offset by higher utility margin, higher allowances for borrowed and equity funds, higher interest and dividend income, lower income tax expense due to the effects of ratemaking, and higher cash surrender value of corporate-owned life insurance policies. Electric utility margin increased primarily due to higher retail rates due to the 2022 regulatory rate review with new rates effective January 2023 and higher transmission and wholesale revenue, partially offset by lower customer volumes and lower regulatory-related revenue deferrals. Electric retail customer volumes, including distribution only service customers, decreased 2.9% primarily due to the unfavorable impact of weather, offset by an increase in the average number of customers. Energy generated decreased 2% for 2023 compared to 2022 primarily due to lower coal-fueled generation, offset by higher natural gas-fueled generation. Wholesale electricity sales volumes decreased 16% and purchased electricity volumes decreased 2%.

Non-GAAP Financial Measure

Management utilizes various key financial measures that are prepared in accordance with GAAP, as well as non-GAAP financial measures such as electric utility margin and natural gas utility margin, to help evaluate results of operations. Electric utility margin is calculated as electric operating revenue less cost of fuel and energy while natural gas utility margin is calculated as natural gas operating revenue less cost of natural gas purchased for resale, which are captions presented on the Consolidated Statements of Operations.

Sierra Pacific's cost of fuel and energy and cost of natural gas purchased for resale are generally recovered from its retail customers through regulatory recovery mechanisms and, as a result, changes in Sierra Pacific's expenses included in regulatory recovery mechanisms result in comparable changes to revenue. As such, management believes electric utility margin and natural gas utility margin more appropriately and concisely explain results of operations rather than a discussion of revenue and cost of sales separately. Management believes the presentation of electric utility margin and natural gas utility margin provides meaningful and valuable insight into the information management considers important to understanding the business and a measure of comparability to others in the industry.

Electric utility margin and natural gas utility margin are not measures calculated in accordance with GAAP and should be viewed as a supplement to, and not a substitute for, operating income, which is the most directly comparable financial measure prepared in accordance with GAAP. The following table provides a reconciliation of utility margin to operating income for the years ended December 31 (in millions):

	2024	2023	Change		2023	2022	Change	
Electric utility margin:								
Operating revenue	\$ 1,080	\$ 1,194	\$ (114)	(10)%	\$ 1,194	\$ 1,025	\$ 169	16 %
Cost of fuel and energy	561	689	(128)	(19)	689	555	134	24
Electric utility margin	519	505	14	3 %	505	470	35	7 %
Natural gas utility margin:								
Operating revenue	182	237	(55)	(23)%	237	168	69	41 %
Cost of natural gas purchased for resale	121	176	(55)	(31)	176	111	65	59
Natural gas utility margin	61	61	—	— %	61	57	4	7 %
Utility margin	580	566	14	2 %	566	527	39	7 %
Operations and maintenance	245	204	41	20 %	204	189	15	8 %
Depreciation and amortization	181	185	(4)	(2)	185	149	36	24
Property and other taxes	24	25	(1)	(4)	25	24	1	4
Operating income	\$ 130	\$ 152	\$ (22)	(14)%	\$ 152	\$ 165	\$ (13)	(8)%

Electric Utility Margin

A comparison of key operating results related to electric utility margin is as follows for the years ended December 31:

	2024	2023	Change		2023	2022	Change	
Utility margin (in millions):								
Operating revenue	\$ 1,080	\$ 1,194	\$ (114)	(10)%	\$ 1,194	\$ 1,025	\$ 169	16 %
Cost of fuel and energy	561	689	(128)	(19)	689	555	134	24
Utility margin	<u>\$ 519</u>	<u>\$ 505</u>	<u>\$ 14</u>	3 %	<u>\$ 505</u>	<u>\$ 470</u>	<u>\$ 35</u>	7 %
Sales (GWhs):								
Residential	2,726	2,655	71	3 %	2,655	2,747	(92)	(3)%
Commercial	3,108	2,998	110	4	2,998	3,124	(126)	(4)
Industrial	2,811	2,684	127	5	2,684	2,867	(183)	(6)
Other	9	11	(2)	(18)	11	13	(2)	(15)
Total fully bundled ⁽¹⁾	8,654	8,348	306	4	8,348	8,751	(403)	(5)
Distribution only service	2,958	2,829	129	5	2,829	2,757	72	3
Total retail	11,612	11,177	435	4	11,177	11,508	(331)	(3)
Wholesale	683	621	62	10	621	741	(120)	(16)
Total GWhs sold	<u>12,295</u>	<u>11,798</u>	<u>497</u>	4 %	<u>11,798</u>	<u>12,249</u>	<u>(451)</u>	(4)%
Average number of retail customers (in thousands)								
	382	376	6	2 %	376	371	5	1 %
Average revenue per MWh:								
Retail - fully bundled ⁽¹⁾	\$116.12	\$132.97	\$ (16.85)	(13)%	\$132.97	\$106.57	\$ 26.40	25 %
Wholesale	\$ 58.60	\$ 79.63	\$ (21.03)	(26)%	\$ 79.63	\$ 75.48	\$ 4.15	5 %
Heating degree days								
	4,379	4,950	(571)	(12)%	4,950	4,631	319	7 %
Cooling degree days	1,422	1,097	325	30 %	1,097	1,353	(256)	(19)%
Sources of energy (GWhs) ⁽²⁾⁽³⁾ :								
Natural gas	4,566	4,310	256	6 %	4,310	4,075	235	6 %
Coal	910	759	151	20	759	1,077	(318)	(30)
Renewables	23	24	(1)	(4)	24	26	(2)	(8)
Total energy generated	5,499	5,093	406	8	5,093	5,178	(85)	(2)
Energy purchased	3,808	4,612	(804)	(17)	4,612	4,691	(79)	(2)
Total	<u>9,307</u>	<u>9,705</u>	<u>(398)</u>	(4)%	<u>9,705</u>	<u>9,869</u>	<u>(164)</u>	(2)%
Average cost of energy per MWh ⁽²⁾⁽⁴⁾ :								
Energy generated	\$ 40.79	\$ 64.82	\$ (24.03)	(37)%	\$ 64.82	\$ 46.05	\$ 18.77	41 %
Energy purchased	\$ 88.33	\$ 77.85	\$ 10.48	13 %	\$ 77.85	\$ 67.49	\$ 10.36	15 %

(1) Fully bundled includes sales to customers for combined energy, transmission and distribution services.

(2) The average cost of energy per MWh and sources of energy excludes 3, 4 and — GWhs of coal and — GWhs of natural gas generated energy that is purchased at cost by related parties for the years ended December 31, 2024, 2023 and 2022, respectively.

(3) GWh amounts are net of energy used by the related generating facilities.

(4) The average cost of energy per MWh includes only the cost of fuel associated with the generating facilities, purchased power and deferrals.

Natural Gas Utility Margin

A comparison of key operating results related to natural gas utility margin is as follows for the years ended December 31:

	2024	2023	Change		2023	2022	Change	
Utility margin (in millions):								
Operating revenue	\$ 182	\$ 237	\$ (55)	(23)%	\$ 237	\$ 168	\$ 69	41 %
Cost of natural gas purchased for resale	121	176	(55)	(31)	176	111	65	59
Utility margin	<u>\$ 61</u>	<u>\$ 61</u>	<u>\$ —</u>	<u>— %</u>	<u>\$ 61</u>	<u>\$ 57</u>	<u>\$ 4</u>	<u>7 %</u>
Sold (000's Dths):								
Residential	10,902	12,200	(1,298)	(11)%	12,200	11,269	931	8 %
Commercial	5,597	6,276	(679)	(11)	6,276	5,897	379	6
Industrial	2,423	2,870	(447)	(16)	2,870	2,211	659	30
Total retail	<u>18,922</u>	<u>21,346</u>	<u>(2,424)</u>	<u>(11)%</u>	<u>21,346</u>	<u>19,377</u>	<u>1,969</u>	<u>10 %</u>
Average number of retail customers (in thousands)								
	185	183	2	1 %	183	180	3	2 %
Average revenue per retail Dth sold								
	\$ 9.62	\$ 11.10	\$ (1.48)	(13)%	\$ 11.10	\$ 8.67	\$ 2.43	28 %
Heating degree days								
	4,379	4,950	(571)	(12)%	4,950	4,631	319	7 %
Average cost of natural gas per retail Dth sold								
	\$ 6.39	\$ 8.25	\$ (1.85)	(23)%	\$ 8.25	\$ 5.73	\$ 2.52	44 %

Year Ended December 31, 2024 Compared to Year Ended December 31, 2023

Electric utility margin increased \$14 million, or 3%, for 2024 compared to 2023 primarily due to:

- \$19 million of higher electric retail utility margin primarily due to higher retail rates from the 2024 regulatory rate review with new rates effective October 2024 and higher retail customer volumes. Retail customer volumes, including distribution only service customers, increased 3.9% primarily due to the favorable impact of weather and an increase in the average number of customers.

The increase in electric utility margin was offset by:

- \$5 million of lower transmission and wholesale revenue.

Operations and maintenance increased \$41 million, or 20%, for 2024 compared to 2023 primarily due to higher insurance premiums due to additional wildfire coverage, increased reserve costs, higher plant operations and maintenance expenses, higher regulatory expenses primarily related to mill tax, increased technology costs, higher administrative and general costs, higher energy efficiency program costs (offset in operating revenue) and regulatory impacts from the 2024 general rate review.

Depreciation and amortization decreased \$4 million, or 2%, for 2024 compared to 2023 primarily due to lower plant amortizations.

Interest expense increased \$20 million, or 30%, for 2024 compared to 2023 primarily due to higher long-term debt with higher average interest rates.

Allowance for equity funds increased \$8 million for 2024 compared to 2023 primarily due to higher construction work-in-progress.

Interest and dividend income decreased \$10 million, or 45%, for 2024 compared to 2023 primarily due to unfavorable interest income, mainly from lower carrying charges on regulatory balances.

Other, net was favorable by \$6 million for 2024 compared to 2023 primarily due to lower pension expense.

Income tax expense decreased \$6 million, or 38%, for 2024 compared to 2023 primarily due to lower pretax income. The effective tax rate was 11% in 2024 and 12% in 2023 and decreased primarily due to the effects of ratemaking.

Year Ended December 31, 2023 Compared to Year Ended December 31, 2022

Electric utility margin increased \$35 million, or 7%, for 2023 compared to 2022 primarily due to:

- \$39 million of higher electric retail utility margin primarily due to higher retail rates due to the 2022 regulatory rate review with new rates effective January 2023, offset by lower retail customer volumes. Retail customer volumes, including distribution only service customers, decreased 2.9% primarily due to the unfavorable impact of weather, offset by an increase in the average number of customers and
- \$2 million of higher transmission and wholesale revenue.

The increase in electric utility margin was offset by:

- \$3 million of lower regulatory-related revenue deferrals.

Natural gas utility margin increased \$4 million, or 7%, for 2023 compared to 2022 primarily due to higher customer volumes from the favorable impact of weather and an increase in the average number of customers.

Operations and maintenance increased \$15 million, or 8%, for 2023 compared to 2022 primarily due to increased plant operations and maintenance expenses, lower regulatory credits from the deferral of the ON Line lease cost reallocation in 2022, higher insurance premiums due to additional wildfire coverage and higher customer service operations expenses, partially offset by lower regulatory approved amortization from the recovery for the ON Line reallocation (offset in operating revenue).

Depreciation and amortization increased \$36 million, or 24%, for 2023 compared to 2022 primarily due to higher plant placed in-service and higher regulatory amortizations.

Interest expense increased \$8 million, or 14%, for 2023 compared to 2022 primarily due to higher long-term debt and higher average interest rates.

Allowance for borrowed funds increased \$4 million for 2023 compared to 2022 primarily due to higher construction work-in-progress.

Allowance for equity funds increased \$7 million for 2023 compared to 2022 primarily due to higher construction work-in-progress.

Interest and dividend income increased \$4 million, or 22%, for 2023 compared to 2022 primarily due to higher interest income, mainly from carrying charges on regulatory balances.

Other, net increased \$2 million for 2023 compared to 2022 primarily due to higher cash surrender value of corporate-owned life insurance policies.

Income tax expense decreased \$3 million, or 16%, for 2023 compared to 2022 primarily due to the effects of ratemaking. The effective tax rate was 12% in 2023 and 14% in 2022.

Liquidity and Capital Resources

As of December 31, 2024, Sierra Pacific's total net liquidity was \$417 million as follows (in millions):

Cash and cash equivalents	\$	17
Credit facilities ⁽¹⁾		400
Total net liquidity	\$	417
Credit facilities:		
Maturity dates		2027

(1) Refer to Note 7 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for further discussion regarding Sierra Pacific's credit facility.

Operating Activities

Net cash flows from operating activities for the years ended December 31, 2024 and 2023 were \$470 million and \$419 million, respectively. The change was primarily due to lower payments related to fuel energy costs and increased customer deposits, partially offset by lower collections from customers, the timing of payments for operating costs, higher interest payments and higher income tax payments.

Net cash flows from operating activities for the years ended December 31, 2023 and 2022 were \$419 million and \$109 million, respectively. The change was primarily due to higher collections from customers and lower payments related to fuel and energy costs, partially offset by higher payments for income taxes, the timing of payments for operating costs and lower customer deposits.

The timing of Sierra Pacific's income tax cash flows from period to period can be significantly affected by the estimated federal income tax payment methods selected and assumptions made for each payment date.

Investing Activities

Net cash flows from investing activities for the years ended December 31, 2024 and 2023 were \$(673) million and \$(388) million, respectively. The change was primarily due to increased capital expenditures. Refer to "Future Uses of Cash" for further discussion of capital expenditures.

Net cash flows from investing activities for the years ended December 31, 2023 and 2022 were \$(388) million and \$(351) million, respectively. The change was primarily due to increased capital expenditures. Refer to "Future Uses of Cash" for further discussion of capital expenditures.

Financing Activities

Net cash flows from financing activities for the years ended December 31, 2024 and 2023 were \$175 million and \$(35) million, respectively. The change was primarily due to a decrease in repayments of long-term debt, higher contributions from NV Energy, Inc. and lower repayments of an affiliate note payable, partially offset by a decrease in proceeds from long-term debt and higher dividends paid to NV Energy, Inc.

Net cash flows from financing activities for the years ended December 31, 2023 and 2022 were \$(35) million and \$282 million, respectively. The change was primarily due to lower contributions from NV Energy, Inc., higher repayments of long-term debt and higher dividends paid to NV Energy, Inc., partially offset by lower long-term debt reacquired, lower repayments of short-term debt and higher proceeds from the issuance of long-term debt.

In January and February 2025, Sierra Pacific received contributions from NV Energy, Inc. of \$275 million.

Debt Authorizations

Sierra Pacific's ability to issue debt is primarily impacted by its financing authority from the PUCN. As of December 31, 2024, Sierra Pacific has financing authority from the PUCN consisting of the ability to issue long-term and short-term debt securities so long as the total amount of debt outstanding (excluding borrowings under Sierra Pacific's \$400 million secured credit facility) does not exceed \$4.0 billion and to issue common and preferred stock so long as the total amounts outstanding do not exceed \$5.1 billion and \$500 million, respectively, as measured at the end of each calendar quarter. Sierra Pacific's revolving credit facility contains a financial maintenance covenant which Sierra Pacific was in compliance with as of December 31, 2024. In addition, certain financing agreements contain covenants which are currently suspended as Sierra Pacific's senior secured debt is rated investment grade. However, if Sierra Pacific's senior secured debt ratings fall below investment grade by either Moody's Investor Service or Standard & Poor's, Sierra Pacific would be subject to limitations under these covenants.

General and Refunding Mortgage Securities

To the extent Sierra Pacific has the ability to issue debt under the most restrictive covenants in its financing agreements and has financing authority to do so from the PUCN, Sierra Pacific's ability to issue secured debt is limited by the amount of bondable property or retired bonds that can be used to issue debt under Sierra Pacific's indenture.

Sierra Pacific's indenture creates a lien on substantially all of Sierra Pacific's properties in Nevada. As of December 31, 2024, \$5.2 billion of Sierra Pacific's assets were pledged. Sierra Pacific had the capacity to issue \$1.6 billion of additional general and refunding mortgage securities as of December 31, 2024 determined on the basis of 70% of net utility property additions. Property additions include plant-in-service and specific assets in construction work-in-progress. The amount of bond capacity listed above does not include eligible property in construction work-in-progress. Sierra Pacific also has the ability to release property from the lien of Sierra Pacific's indenture on the basis of net property additions, cash or retired bonds. To the extent Sierra Pacific releases property from the lien of Sierra Pacific's indenture, it will reduce the amount of securities issuable under the indenture.

Future Uses of Cash

Sierra Pacific has available a variety of sources of liquidity and capital resources, both internal and external, including net cash flows from operating activities, public and private debt offerings, the use of secured revolving credit facilities, capital contributions and other sources. These sources are expected to provide funds required for current operations, capital expenditures, debt retirements and other capital requirements. The availability and terms under which Sierra Pacific has access to external financing depends on a variety of factors, including Sierra Pacific's credit ratings, investors' judgment of risk associated with Sierra Pacific and conditions in the overall capital markets, including the condition of the utility industry.

Capital Expenditures

Capital expenditure needs are reviewed regularly by management and may change significantly as a result of these reviews, which may consider, among other factors, changes in environmental and other rules and regulations; impacts to customers' rates; outcomes of regulatory proceedings; changes in income tax laws; general business conditions; load projections; system reliability standards; the cost and efficiency of construction labor, equipment and materials; commodity prices; and the cost and availability of capital. Prudently incurred expenditures for compliance-related items such as pollution-control technologies, replacement generation and associated operating costs are generally incorporated into Sierra Pacific's regulated retail rates. Expenditures for certain assets may ultimately include acquisition of existing assets.

Historical and forecasted capital expenditures, each of which exclude amounts for non-cash equity AFUDC and other non-cash items, for the years ending December 31 are as follows (in millions):

	Historical			Forecast		
	2022	2023	2024	2025	2026	2027
Electric distribution	\$ 73	\$ 148	\$ 194	\$ 196	\$ 285	\$ 292
Electric transmission	75	114	161	115	582	412
Solar generation	36	1	96	26	304	314
Electric battery storage	—	14	102	345	96	10
Wildfire mitigation	40	21	40	84	92	93
Other	127	90	81	176	178	367
Total	<u>\$ 351</u>	<u>\$ 388</u>	<u>\$ 674</u>	<u>\$ 942</u>	<u>\$ 1,537</u>	<u>\$ 1,488</u>

Sierra Pacific received or is seeking PUCN approval through its recent IRP filings for an increase in solar generation and electric transmission and has included estimates from its latest IRP filing as well as potential future filings in its forecast capital expenditures for 2025 through 2027. These estimates are likely to change as a result of the RFP process, continued evaluation and future IRP filing refinements. Sierra Pacific's historical and forecast capital expenditures include the following:

- Electric distribution includes both growth projects and operating expenditures consisting of routine expenditures for distribution needed to serve existing and expected demand.
- Electric transmission includes both growth projects and operating expenditures. Growth projects primarily relate to the Nevada Utilities' Greenlink Nevada transmission expansion program totaling \$84 million for 2024, \$68 million for 2023, \$9 million for 2022. Planned spending for the expansion program expected to be placed in-service in 2027 and 2028 totals \$82 million in 2025, \$544 million in 2026 and \$386 million in 2027. Operating expenditures consist of routine expenditures for transmission and other infrastructure needed to serve existing and expected demand.
- Solar generation includes solar photovoltaic panels procured for future growth projects and a 400-MW solar photovoltaic facility with an additional 400-MW of co-located battery storage that would be developed in Churchill County, Nevada with ownership share approved by the PUCN of 90% Sierra Pacific and 10% Nevada Power of which commercial operation of the solar facility is expected by early 2027.
- Electric battery storage includes a 400-MW battery energy storage system co-located with a 400-MW solar photovoltaic facility that is being developed in Churchill County, Nevada with ownership share approved by the PUCN of 90% Sierra Pacific and 10% Nevada Power of which commercial operation of the battery energy storage system is expected by mid-2026.
- Wildfire mitigation includes operating expenditures for wildfire mitigation activities totaling \$23 million in 2024, \$16 million in 2023, \$20 million in 2022, Planned spending for wildfire mitigation consists of \$41 million in 2025, \$60 million in 2026 and \$51 million in 2027 is comprised of reducing wildfire risk in Tier 3 HTAs by rebuilding distribution lines with covered conductor, converting overhead distribution lines to underground and copper wire and pole replacement projects.
- Other includes both growth projects and operating expenditures consisting of a repower project at the Valmy generating station to convert existing coal-fired combustion to natural gas-fired combustion, a hydrogen-capable natural gas simple cycle combustion turbine peakers project at the Valmy generating station, information technology expenditures, routine expenditures for generation, other operating projects and other infrastructure needed to serve existing and expected demand.

2021 Joint Integrated Resource Plan

In August 2023, the Nevada Utilities filed its Joint Application for approval of the Fifth Amendment to the 2021 Joint Integrated Resource Plan. The Fifth Amendment sought, in part (1) to convert the existing coal-fueled generating facility at North Valmy Generating Station to a cleaner natural gas-fueled generating facility (2) to purchase, install, and operate a company-owned 400 MW solar plant along with a 400 MW, four-hour battery storage system in Northern Nevada; (3) to continue operation of Tracy units 4 and 5 to 2049; (4) to purchase development assets for the 149 MW photovoltaic and 149 MW battery energy storage system Crescent Valley Solar project; (5) to construct the Esmeralda and Amargosa substations transformers; and (6) to construct the necessary infrastructure in the APEX Area Master Plan. The Nevada Utilities seek approval of approximately \$1.8 billion in total costs of new projects of which Sierra Pacific's share is approximately \$0.8 billion. An order was issued in March 2024 in which the Nevada Utilities filed a motion for clarification and petition for reconsideration. In April 2024, a modified final order was issued, which granted in part and denied in part including the denial of the 149 MW photovoltaic and 149 MW battery energy storage system Crescent Valley Solar project as delineated in the final modified order.

2024 Joint Integrated Resource Plan

In May 2024, the Nevada Utilities filed its joint Application for approval of the 2024 Joint Integrated Resources Plan. The 2024 joint Application sought, in part (1) the addition of three power purchase agreements for solar generating resources totaling more than 1,000 MW, each with co-located battery storage systems; (2) the addition of 400 MW of company-owned hydrogen-capable natural gas simple cycle combustion turbine peakers at the North Valmy generation station; (3) to approve an update of the Greenlink Nevada Transmission project costs; and (4) to construct the necessary transmission infrastructure to support growing customer demand. In December 2024, the PUCN largely accepted the filing as filed but denied opining on the additional costs associated with the Greenlink Nevada project as all costs expended to construct the previously approved Greenlink Nevada project are subject to a prudence review in the GRC as delineated in the final 2024 Joint Integrated Resource Plan order.

Material Cash Requirements

Sierra Pacific has cash requirements that may affect its consolidated financial condition that arise primarily from long- and short-term debt (refer to Notes 7 and 8), operating and financing leases (refer to Note 5), purchased electricity contracts (refer to Note 14), fuel contracts (refer to Note 14), construction and other development costs (refer to Liquidity and Capital Resources included within this Item 7 and Note 14) and AROs (refer to Note 11). Refer to the respective referenced note in Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

Sierra Pacific has cash requirements relating to interest payments of \$1.3 billion on long-term debt, including \$72 million due in 2025.

Regulatory Matters

Sierra Pacific is subject to comprehensive regulation. Refer to the discussion contained in Item 1 of this Form 10-K for further information regarding Sierra Pacific's general regulatory framework and current regulatory matters.

Environmental Laws and Regulations

Sierra Pacific is subject to federal, state and local laws and regulations regarding air quality, climate change, emissions performance standards, water quality, coal ash disposal and other environmental matters that have the potential to impact Sierra Pacific's current and future operations. In addition to imposing continuing compliance obligations, these laws and regulations provide regulators with the authority to levy substantial penalties for noncompliance including fines, injunctive relief and other sanctions. These laws and regulations are administered by various federal, state and local agencies. Sierra Pacific believes it is in material compliance with all applicable laws and regulations, although many are subject to interpretation that may ultimately be resolved by the courts. Environmental laws and regulations continue to evolve, and Sierra Pacific is unable to predict the impact of the changing laws and regulations on its operations and financial results.

Refer to "Environmental Laws and Regulations" in Item 1 of this Form 10-K for further discussion regarding environmental laws and regulations.

Collateral and Contingent Features

Debt of Sierra Pacific is rated by credit rating agencies. Assigned credit ratings are based on each rating agency's assessment of Sierra Pacific's ability to, in general, meet the obligations of its issued debt. The credit ratings are not a recommendation to buy, sell or hold securities, and there is no assurance that a particular credit rating will continue for any given period of time.

Sierra Pacific has no credit rating downgrade triggers that would accelerate the maturity dates of outstanding debt, and a change in ratings is not an event of default under the applicable debt instruments. Sierra Pacific's secured revolving credit facility does not require the maintenance of a minimum credit rating level in order to draw upon its availability. However, commitment fees and interest rates under the credit facility are tied to credit ratings and increase or decrease when the ratings change. A ratings downgrade could also increase the future cost of commercial paper, short- and long-term debt issuances or new credit facilities.

In accordance with industry practice, certain wholesale agreements, including derivative contracts, contain credit support provisions that in part base certain collateral requirements on credit ratings for unsecured debt as reported by one or more of the recognized credit rating agencies. These agreements may either specifically provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed specified rating-dependent threshold levels ("credit-risk-related contingent features") or provide the right for counterparties to demand "adequate assurance," or in some cases terminate the contract, in the event of a material adverse change in creditworthiness. These rights can vary by contract and by counterparty. As of December 31, 2024, the applicable credit ratings obtained from recognized credit rating agencies were investment grade. If all credit-risk-related contingent features or adequate assurance provisions for these agreements had been triggered as of December 31, 2024, Sierra Pacific would have been required to post \$33 million of additional collateral. Sierra Pacific's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation, or other factors.

Inflation

Historically, overall inflation and changing prices in the economies where Sierra Pacific operates has not had a significant impact on Sierra Pacific's financial results. Sierra Pacific operates under a cost-of-service based rate-setting structure administered by the PUCN and the FERC. Under this rate-setting structure, Sierra Pacific is allowed to include prudent costs in its rates, including the impact of inflation after Sierra Pacific experiences cost increases. Fuel and purchase power costs are recovered through a balancing account, minimizing the impact of inflation related to these costs. Sierra Pacific attempts to minimize the potential impact of inflation on its operations through the use of periodic rate adjustments for fuel and energy costs, by employing prudent risk management and hedging strategies and by considering, among other areas, its impact on purchases of energy, operating expenses, materials and equipment costs, contract negotiations, future capital spending programs and long-term debt issuances. There can be no assurance that such actions will be successful.

New Accounting Pronouncements

For a discussion of new accounting pronouncements affecting Sierra Pacific, refer to Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Critical Accounting Estimates

Certain accounting measurements require management to make estimates and judgments concerning transactions that will be settled several years in the future. Amounts recognized on the Consolidated Financial Statements based on such estimates involve numerous assumptions subject to varying and potentially significant degrees of judgment and uncertainty and will likely change in the future as additional information becomes available. The following critical accounting estimates are impacted significantly by Sierra Pacific's methods, judgments and assumptions used in the preparation of the Consolidated Financial Statements and should be read in conjunction with Sierra Pacific's Summary of Significant Accounting Policies included in Sierra Pacific's Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Accounting for the Effects of Certain Types of Regulation

Sierra Pacific prepares its Consolidated Financial Statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, Sierra Pacific defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in regulated rates occur.

Sierra Pacific continually evaluates the applicability of the guidance for regulated operations and whether its regulatory assets and liabilities are probable of inclusion in future regulated rates by considering factors such as a change in the regulator's approach to setting rates from cost-based ratemaking to another form of regulation, other regulatory actions or the impact of competition that could limit Sierra Pacific's ability to recover its costs. Sierra Pacific believes its application of the guidance for regulated operations is appropriate and its existing regulatory assets and liabilities are probable of inclusion in future regulated rates. The evaluation reflects the current political and regulatory climate at both the federal and state levels. If it becomes no longer probable that the deferred costs or income will be included in future regulated rates, the related regulatory assets and liabilities will be written off to net income, returned to customers or re-established as AOCI. Total regulatory assets were \$292 million and total regulatory liabilities were \$522 million as of December 31, 2024. Refer to Sierra Pacific's Note 6 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding Sierra Pacific's regulatory assets and liabilities.

Impairment of Long-Lived Assets

Sierra Pacific evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or when the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value and any resulting impairment loss is reflected on the Consolidated Statements of Operations. As substantially all property, plant and equipment was used in regulated businesses as of December 31, 2024, the impacts of regulation are considered when evaluating the carrying value of regulated assets.

The estimate of cash flows arising from the future use of an asset, for the purposes of impairment analysis, requires the exercise of judgment. Circumstances that could significantly alter the calculation of fair value or the recoverable amount of an asset may include significant changes in the regulatory environment, the business climate, management's plans, legal factors, market price of the asset, the use of the asset, the physical condition of the asset, future market prices, load growth, competition and many other factors over the life of the asset. Any resulting impairment loss is highly dependent on the underlying assumptions and could significantly affect Sierra Pacific's results of operations.

Income Taxes

In determining Sierra Pacific's income taxes, management is required to interpret complex income tax laws and regulations, which includes consideration of regulatory implications imposed by Sierra Pacific's various regulatory commissions. Sierra Pacific's income tax returns are subject to continuous examinations by federal, state and local income tax authorities that may give rise to different interpretations of these complex laws and regulations. Due to the nature of the examination process, it generally takes years before these examinations are completed and these matters are resolved. Sierra Pacific recognizes the tax benefit from an uncertain tax position only if it is more-likely-than-not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the Consolidated Financial Statements from such a position are measured based on the largest benefit that is more-likely-than-not to be realized upon ultimate settlement. Although the ultimate resolution of Sierra Pacific's federal, state and local income tax examinations is uncertain, Sierra Pacific believes it has made adequate provisions for these income tax positions. The aggregate amount of any additional income tax liabilities that may result from these examinations is not expected to have a material impact on Sierra Pacific's financial results. Refer to Sierra Pacific's Note 9 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding Sierra Pacific's income taxes.

It is probable that Sierra Pacific will pass income tax benefit and expense related to the federal tax rate change from 35% to 21%, certain property-related basis differences and other various differences on to its customers. As of December 31, 2024, these amounts were recognized as a net regulatory liability of \$193 million and will be included in regulated rates when the temporary differences reverse.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Sierra Pacific's Consolidated Balance Sheets include assets and liabilities with fair values that are subject to market risks. Sierra Pacific's significant market risks are primarily associated with commodity prices, interest rates and the extension of credit to counterparties with which Sierra Pacific transacts. The following discussion addresses the significant market risks associated with Sierra Pacific's business activities. Sierra Pacific has established guidelines for credit risk management. Refer to Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding Sierra Pacific's contracts accounted for as derivatives.

Commodity Price Risk

Sierra Pacific is exposed to the impact of market fluctuations in commodity prices and interest rates. Sierra Pacific is principally exposed to electricity, natural gas and coal market fluctuations primarily through Sierra Pacific's obligation to serve retail customer load in its regulated service territory. Sierra Pacific's load and generating facilities represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel required to generate electricity, wholesale electricity that is purchased and sold, and natural gas supply for retail customers. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather, market liquidity, generating facility availability, customer usage, storage, and transmission and transportation constraints. The actual cost of fuel and purchased power is recoverable through the deferred energy mechanism. Interest rate risk exists on variable-rate debt and future debt issuances. Sierra Pacific does not engage in proprietary trading activities. To mitigate a portion of its commodity price risk, Sierra Pacific uses commodity derivative contracts, which may include forwards, futures, options, swaps and other agreements, to effectively secure future supply or sell future production generally at fixed prices. Sierra Pacific does not hedge all of its commodity price risk, thereby exposing the unhedged portion to changes in market prices. Sierra Pacific's exposure to commodity price risk is generally limited by its ability to include commodity costs in regulated rates through its deferred energy mechanism, which is subject to disallowance and regulatory lag that occurs between the time the costs are incurred and when the costs are included in regulated rates, as well as the impact of any customer sharing resulting from cost adjustment mechanisms.

The table that follows summarizes Sierra Pacific's price risk on commodity contracts accounted for as derivatives and shows the effects of a hypothetical 10% increase and 10% decrease in forward market prices by the expected volumes for these contracts as of that date. The selected hypothetical change does not reflect what could be considered the best or worse case scenarios (dollars in millions).

	Fair Value - Net Asset (Liability)	Estimated Fair Value after Hypothetical Change in Price	
		10% increase	10% decrease
<u>As of December 31, 2024:</u>			
Total commodity derivative contracts	\$ (13)	\$ (12)	\$ (14)
<u>As of December 31, 2023:</u>			
Total commodity derivative contracts	\$ (16)	\$ (14)	\$ (18)

Sierra Pacific's commodity derivative contracts not designated as hedging contracts are recoverable from customers in regulated rates and therefore, net unrealized gains and losses associated with interim price movements on commodity derivative contracts do not expose Sierra Pacific to earnings volatility. As of December 31, 2024 and 2023, a net regulatory asset of \$13 million and \$16 million, respectively, was recorded related to the net derivative liability of \$13 million and \$16 million, respectively. The settled cost of these commodity derivative contracts is generally included in regulated rates.

Interest Rate Risk

Sierra Pacific is exposed to interest rate risk on its outstanding variable-rate short- and long-term debt and future debt issuances. Sierra Pacific manages its interest rate risk by limiting its exposure to variable interest rates primarily through the issuance of fixed-rate long-term debt and by monitoring market changes in interest rates. As a result of the fixed interest rates, Sierra Pacific's fixed-rate long-term debt does not expose Sierra Pacific to the risk of loss due to changes in market interest rates. Additionally, because fixed-rate long-term debt is not carried at fair value on the Consolidated Balance Sheets, changes in fair value would impact earnings and cash flows only if Sierra Pacific were to reacquire all or a portion of these instruments prior to their maturity. The nature and amount of Sierra Pacific's short- and long-term debt can be expected to vary from period to period as a result of future business requirements, market conditions and other factors. Refer to Notes 7 and 8 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional discussion of Sierra Pacific's short- and long-term debt.

As of December 31, 2024 and 2023, Sierra Pacific had no short- and long-term variable-rate obligations that expose Sierra Pacific to the risk of increased interest expense in the event of increases in short-term interest rates.

Credit Risk

Sierra Pacific is exposed to counterparty credit risk associated with wholesale energy supply and marketing activities with other utilities, energy marketing companies, financial institutions and other market participants. Credit risk may be concentrated to the extent Sierra Pacific's counterparties have similar economic, industry or other characteristics and due to direct and indirect relationships among the counterparties. Before entering into a transaction, Sierra Pacific analyzes the financial condition of each significant wholesale counterparty, establishes limits on the amount of unsecured credit to be extended to each counterparty and evaluates the appropriateness of unsecured credit limits on an ongoing basis. To further mitigate wholesale counterparty credit risk, Sierra Pacific enters into netting and collateral arrangements that may include margining and cross-product netting agreements and obtain third-party guarantees, letters of credit and cash deposits. If required, Sierra Pacific exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

As of December 31, 2024, Sierra Pacific's aggregate credit exposure from energy related transactions were not material, based on settlement and mark-to-market exposures, net of collateral.

Item 8. Financial Statements and Supplementary Data	
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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Sierra Pacific Power Company

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Sierra Pacific Power Company and subsidiaries ("Sierra Pacific") as of December 31, 2024 and 2023, the related consolidated statements of operations, changes in shareholder's equity, and cash flows, for each of the three years in the period ended December 31, 2024, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of Sierra Pacific as of December 31, 2024 and 2023, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2024, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of Sierra Pacific's management. Our responsibility is to express an opinion on Sierra Pacific's financial statements 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 Sierra Pacific 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Sierra Pacific is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of Sierra Pacific's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the 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 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 financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the executive committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the 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.

Regulatory Matters — Effects of Rate Regulation on the Financial Statements — Refer to Note 6 to the financial statements

Critical Audit Matter Description

Sierra Pacific is subject to rate regulation by a state public service commission as well as the Federal Energy Regulatory Commission (collectively, the "Commissions"), which have jurisdiction with respect to the rates of electric and natural gas companies in the respective service territories where Sierra Pacific operates. Management has determined its regulated operations meet the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the specialized rules to account for the effects of cost-based rate regulation. Accounting for the economic effects of rate regulation has a pervasive effect on the financial statements.

Regulated rates are subject to regulatory rate-setting processes. Rates are determined, approved, and established based on a cost-of-service basis, which is designed to allow Sierra Pacific an opportunity to recover its prudently incurred costs of providing services and to earn a reasonable return on its invested capital. Regulatory decisions can have an effect on the recovery of costs, the rate of return earned on investment, and the timing and amount of assets to be recovered by rates. While Sierra Pacific Power Company has indicated it expects to recover costs from customers through regulated rates, there is a risk that changes to the Commissions' approach to setting rates or other regulatory actions could limit Sierra Pacific's ability to recover its costs.

We identified the effects of rate regulation on the financial statements as a critical audit matter due to the significant judgments made by management to support its assertions about affected account balances and disclosures and the high degree of subjectivity involved in assessing the impact of regulatory orders on the financial statements. Management judgments include assessing the likelihood of (1) recovery in future rates of incurred costs and (2) a refund to customers. Given that management's accounting judgments are based on assumptions about the outcome of decisions by the Commissions, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate setting process due to its inherent complexities.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the uncertainty of decisions by the Commissions included the following, among others:

- We evaluated Sierra Pacific's disclosures related to the effects of rate regulation by testing recorded balances and evaluating regulatory developments.
- We read relevant regulatory orders issued by the Commissions, regulatory statutes, filings made by Sierra Pacific and intervenors, and other external information. We evaluated relevant external information and compared it to certain recorded regulatory asset and liability balances for completeness.
- For certain regulatory matters, we inspected Sierra Pacific's filings with the Commissions and the filings with the Commissions by intervenors to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedents of the Commissions' treatment of similar costs under similar circumstances.
- We inquired of management about property, plant, and equipment that may be abandoned. We inquired of management to identify projects that are designed to replace assets that may be retired prior to the end of the useful life. We inspected minutes of the board of directors and regulatory orders and other filings with the Commissions to identify any evidence that may contradict management's assertion regarding probability of an abandonment.

/s/ Deloitte & Touche LLP

Las Vegas, Nevada
February 21, 2025

We have served as Sierra Pacific's auditor since 1996.

SIERRA PACIFIC POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Amounts in millions, except share data)

	As of December 31,	
	2024	2023
ASSETS		
Current assets:		
Cash and cash equivalents	\$ 17	\$ 44
Trade receivables, net	138	180
Inventories	161	117
Regulatory assets	90	161
Prepayments	54	15
Other current assets	22	20
Total current assets	482	537
Property, plant and equipment, net	4,439	3,822
Regulatory assets	202	220
Other assets	204	193
Total assets	\$ 5,327	\$ 4,772
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities:		
Accounts payable	\$ 410	\$ 228
Accrued interest	19	18
Accrued property, income and other taxes	16	21
Regulatory liabilities	106	15
Customer deposits	42	21
Other current liabilities	50	46
Total current liabilities	643	349
Long-term debt	1,527	1,293
Regulatory liabilities	416	424
Deferred income taxes	369	404
Other long-term liabilities	272	237
Total liabilities	3,227	2,707
Commitments and contingencies (Note 14)		
Shareholder's equity:		
Common stock - \$3.75 stated value, 1,000 shares authorized, issued and outstanding	—	—
Additional paid-in capital	1,726	1,576
Retained earnings	375	490
Accumulated other comprehensive loss, net	(1)	(1)
Total shareholder's equity	2,100	2,065
Total liabilities and shareholder's equity	\$ 5,327	\$ 4,772

The accompanying notes are an integral part of these consolidated financial statements.

SIERRA PACIFIC POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

(Amounts in millions)

	Years Ended December 31,		
	2024	2023	2022
Operating revenue:			
Regulated electric	\$ 1,080	\$ 1,194	\$ 1,025
Regulated natural gas	182	237	168
Total operating revenue	1,262	1,431	1,193
Operating expenses:			
Cost of fuel and energy	561	689	555
Cost of natural gas purchased for resale	121	176	111
Operations and maintenance	245	204	189
Depreciation and amortization	181	185	149
Property and other taxes	24	25	24
Total operating expenses	1,132	1,279	1,028
Operating income	130	152	165
Other income (expense):			
Interest expense	(86)	(66)	(58)
Allowance for borrowed funds	7	7	3
Allowance for equity funds	22	14	7
Interest and dividend income	12	22	18
Other, net	10	4	2
Total other income (expense)	(35)	(19)	(28)
Income before income tax expense (benefit)	95	133	137
Income tax expense (benefit)	10	16	19
Net income	<u>\$ 85</u>	<u>\$ 117</u>	<u>\$ 118</u>

The accompanying notes are an integral part of these consolidated financial statements.

SIERRA PACIFIC POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY
(Amounts in millions, except shares)

	Common Stock		Other	Retained	Accumulated	Total
	Shares	Amount	Paid-in	Earnings	Other	Shareholder's
			Capital	(Accumulated	Comprehensive	Equity
				Deficit)	Loss, Net	
Balance, December 31, 2021	1,000	\$ —	\$ 1,111	\$ 425	\$ (1)	\$ 1,535
Net income	—	—	—	118	—	118
Dividends declared	—	—	—	(70)	—	(70)
Contributions	—	—	465	—	—	465
Balance, December 31, 2022	1,000	—	1,576	473	(1)	2,048
Net income	—	—	—	117	—	117
Dividends declared	—	—	—	(100)	—	(100)
Balance, December 31, 2023	1,000	—	1,576	490	(1)	2,065
Net income	—	—	—	85	—	85
Dividends declared	—	—	—	(200)	—	(200)
Contributions	—	—	150	—	—	150
Balance, December 31, 2024	1,000	\$ —	\$ 1,726	\$ 375	\$ (1)	\$ 2,100

The accompanying notes are an integral part of these consolidated financial statements.

SIERRA PACIFIC POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Amounts in millions)

	Years Ended December 31,		
	2024	2023	2022
Cash flows from operating activities:			
Net income	\$ 85	\$ 117	\$ 118
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	181	185	149
Allowance for equity funds	(22)	(14)	(7)
Deferred energy	135	117	(267)
Amortization of deferred energy	28	83	97
Other changes in regulatory assets and liabilities	5	1	(1)
Deferred income taxes and amortization of investment tax credits	(49)	(56)	31
Other, net	(1)	—	3
Changes in other operating assets and liabilities:			
Trade receivables and other assets	13	(7)	(52)
Inventories	(44)	(38)	(14)
Accrued property, income and other taxes	(10)	18	(13)
Accounts payable and other liabilities	149	13	65
Net cash flows from operating activities	<u>470</u>	<u>419</u>	<u>109</u>
Cash flows from investing activities:			
Capital expenditures	(674)	(388)	(351)
Proceeds from sale of marketable securities	1	—	—
Net cash flows from investing activities	<u>(673)</u>	<u>(388)</u>	<u>(351)</u>
Cash flows from financing activities:			
Proceeds from long-term debt	233	393	248
Long-term debt reacquired	—	—	(265)
Repayments of long-term debt	—	(250)	—
Net repayments of short-term debt	—	—	(159)
Net (repayments of) proceeds from affiliate note payable	—	(70)	70
Dividends paid	(200)	(100)	(70)
Contributions from parent	150	—	465
Other, net	(8)	(8)	(7)
Net cash flows from financing activities	<u>175</u>	<u>(35)</u>	<u>282</u>
Net change in cash and cash equivalents and restricted cash and cash equivalents	(28)	(4)	40
Cash and cash equivalents and restricted cash and cash equivalents at beginning of period	52	56	16
Cash and cash equivalents and restricted cash and cash equivalents at end of period	<u>\$ 24</u>	<u>\$ 52</u>	<u>\$ 56</u>

The accompanying notes are an integral part of these consolidated financial statements.

SIERRA PACIFIC POWER COMPANY AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Organization and Operations

Sierra Pacific Power Company and its subsidiaries ("Sierra Pacific") is a wholly owned subsidiary of NV Energy, Inc. ("NV Energy"), a holding company that also owns Nevada Power Company and its subsidiaries ("Nevada Power") and certain other subsidiaries. Sierra Pacific is a U.S. regulated electric utility company serving retail customers, including residential, commercial and industrial customers and regulated retail natural gas customers primarily in northern Nevada. NV Energy is an indirect wholly owned subsidiary of Berkshire Hathaway Energy Company ("BHE"). BHE is a holding company based in Des Moines, Iowa that has investments in subsidiaries principally engaged in energy businesses. BHE is a wholly owned subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway").

(2) Summary of Significant Accounting Policies

Basis of Consolidation and Presentation

The Consolidated Financial Statements include the accounts of Sierra Pacific and its subsidiaries in which it holds a controlling financial interest as of the financial statement date. Intercompany accounts and transactions have been eliminated. The Consolidated Statements of Comprehensive Income have been omitted as net income equals comprehensive income for the years ended December 31, 2024, 2023 and 2022.

Use of Estimates in Preparation of Financial Statements

The preparation of the Consolidated Financial Statements in conformity with accounting principles generally accepted in the United States of America ("GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the period. These estimates include, but are not limited to, the effects of regulation; recovery of long-lived assets; certain assumptions made in accounting for pension and other postretirement benefits; asset retirement obligations ("AROs"); income taxes; unbilled revenue; valuation of certain financial assets and liabilities, including derivative contracts; and accounting for contingencies. Actual results may differ from the estimates used in preparing the Consolidated Financial Statements.

Accounting for the Effects of Certain Types of Regulation

Sierra Pacific prepares its Consolidated Financial Statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, Sierra Pacific defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in regulated rates occur. If it becomes no longer probable that the deferred costs or income will be included in future regulated rates, the related regulatory assets and liabilities will be written off to net income, returned to customers or re-established as accumulated other comprehensive income (loss) ("AOCI").

Fair Value Measurements

As defined under GAAP, fair value is the price that would be received to sell an asset or paid to transfer a liability between market participants in the principal market or in the most advantageous market when no principal market exists. Adjustments to transaction prices or quoted market prices may be required in illiquid or disorderly markets in order to estimate fair value. Different valuation techniques may be appropriate under the circumstances to determine the value that would be received to sell an asset or paid to transfer a liability in an orderly transaction. Market participants are assumed to be independent, knowledgeable, able and willing to transact an exchange and not under duress. Nonperformance or credit risk is considered when determining fair value. Considerable judgment may be required in interpreting market data used to develop the estimates of fair value. Accordingly, estimates of fair value presented herein are not necessarily indicative of the amounts that could be realized in a current or future market exchange.

Cash and Cash Equivalents and Restricted Cash

Cash equivalents consist of funds invested in money market mutual funds, U.S. Treasury Bills and other investments with a maturity of three months or less when purchased. Cash and cash equivalents exclude amounts where availability is restricted by legal requirements, loan agreements or other contractual provisions. Restricted cash and cash equivalents consist of funds restricted by the Public Utilities Commission of Nevada ("PUCN") for a certain renewable energy contract. A reconciliation of cash and cash equivalents and restricted cash and cash equivalents as of December 31, 2024 and December 31, 2023, as presented on the Consolidated Statements of Cash Flows is outlined below and disaggregated by the line items in which they appear on the Consolidated Balance Sheets (in millions):

	As of December 31,	
	2024	2023
Cash and cash equivalents	\$ 17	\$ 44
Restricted cash and cash equivalents included in other current assets	7	8
Total cash and cash equivalents and restricted cash and cash equivalents	<u>\$ 24</u>	<u>\$ 52</u>

Allowance for Credit Losses

Trade receivables are primarily short-term in nature with stated collection terms of less than one year from the date of origination and are stated at the outstanding principal amount, net of an estimated allowance for credit losses. The allowance for credit losses is based on Sierra Pacific's assessment of the collectability of amounts owed to Sierra Pacific by its customers. This assessment requires judgment regarding the ability of customers to pay or the outcome of any pending disputes. In measuring the allowance for credit losses for trade receivables, Sierra Pacific primarily utilizes credit loss history. However, Sierra Pacific may adjust the allowance for credit losses to reflect current conditions and reasonable and supportable forecasts that deviate from historical experience. Sierra Pacific also has the ability to assess deposits on customers who have delayed payments or who are deemed to be a credit risk. The changes in the balance of the allowance for credit losses, which is included in trade receivables, net on the Consolidated Balance Sheets, is summarized as follows for the years ended December 31, (in millions):

	2024	2023	2022
Beginning balance	\$ 3	\$ 2	\$ 1
Charged to operating costs and expenses, net	4	4	2
Write-offs, net	(3)	(3)	(1)
Ending balance	<u>\$ 4</u>	<u>\$ 3</u>	<u>\$ 2</u>

Derivatives

Sierra Pacific employs a number of different derivative contracts, which may include forwards, futures, options, swaps and other agreements, to manage its commodity price and interest rate risk. Derivative contracts are recorded on the Consolidated Balance Sheets as either assets or liabilities and are stated at estimated fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by GAAP. Derivative balances reflect offsetting permitted under master netting agreements with counterparties and cash collateral paid or received under such agreements.

Commodity derivatives used in normal business operations that are settled by physical delivery, among other criteria, are eligible for and may be designated as normal purchases or normal sales. Normal purchases or normal sales contracts are not marked-to-market and settled amounts are recognized as cost of fuel, energy and capacity or natural gas purchased for resale on the Consolidated Statements of Operations.

For Sierra Pacific's derivative contracts, the settled amount is generally included in regulated rates. Accordingly, the net unrealized gains and losses associated with interim price movements on contracts that are accounted for as derivatives and probable of inclusion in regulated rates are recorded as regulatory assets and liabilities. For a derivative contract not probable of inclusion in rates, changes in the fair value are recognized in earnings.

Inventories

Inventories consist mainly of materials and supplies totaling \$129 million and \$95 million as of December 31, 2024 and 2023, respectively, and fuel, which includes coal stock, stored natural gas and fuel oil, totaling \$32 million and \$22 million as of December 31, 2024 and 2023, respectively. The cost is determined using the average cost method. Materials are charged to inventory when purchased and are expensed or capitalized to construction work in process, as appropriate, when used. Fuel costs are recovered from retail customers through the base tariff energy rates and deferred energy accounting adjustment charges approved by the PUCN.

Property, Plant and Equipment, Net

General

Additions to property, plant and equipment are recorded at cost. Sierra Pacific capitalizes all construction-related material, direct labor and contract services, as well as indirect construction costs. Indirect construction costs include debt allowance for funds used during construction ("AFUDC"), and equity AFUDC, as applicable. The cost of additions and betterments are capitalized, while costs incurred that do not improve or extend the useful lives of the related assets are generally expensed. The cost of repairs and minor replacements are charged to expense when incurred with the exception of costs for generation plant maintenance under certain long-term service agreements. Costs under these agreements are expensed straight-line over the term of the agreements as approved by the PUCN.

Depreciation and amortization are generally computed by applying the composite or straight-line method based on either estimated useful lives or mandated recovery periods as prescribed by Sierra Pacific's various regulatory authorities. Depreciation studies are completed by Sierra Pacific to determine the appropriate group lives, net salvage and group depreciation rates. These studies are reviewed and rates are ultimately approved by the applicable regulatory commission. Net salvage includes the estimated future residual values of the assets and any estimated removal costs recovered through approved depreciation rates. Estimated removal costs are recorded as a non-current regulatory liability on the Consolidated Balance Sheets. As actual removal costs are incurred, the associated liability is reduced.

Generally when Sierra Pacific retires or sells a component of regulated property, plant and equipment depreciated using the composite method, it charges the original cost, net of any proceeds from the disposition, to accumulated depreciation. Any gain or loss on disposals of all other assets is recorded through earnings with the exception of material gains or losses on regulated property, plant and equipment depreciated on a straight-line basis, which is then recorded to a regulatory liability or asset, respectively.

Debt and equity AFUDC, which represent the estimated costs of debt and equity funds necessary to finance the construction of regulated facilities, are capitalized as a component of property, plant and equipment, with offsetting credits to the Consolidated Statements of Operations. The rate applied to construction costs is the lower of the PUCN allowed rate of return and rates computed based on guidelines set forth by the Federal Energy Regulatory Commission ("FERC"). After construction is completed, Sierra Pacific is permitted to earn a return on these costs as a component of the related assets, as well as recover these costs through depreciation expense over the useful lives of the related assets. Sierra Pacific's AFUDC rate used during 2024 and 2023 was 7.06% and 6.85%, respectively, for electric, 6.14% and 5.75%, respectively, for natural gas and 7.06% and 6.76%, respectively, for common facilities.

Asset Retirement Obligations

Sierra Pacific recognizes AROs when it has a legal obligation to perform decommissioning, reclamation or removal activities upon retirement of an asset. Sierra Pacific's AROs are primarily associated with its generating facilities. The fair value of an ARO liability is recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made, and is added to the carrying amount of the associated asset, which is then depreciated over the remaining useful life of the asset. Subsequent to the initial recognition, the ARO liability is adjusted for any revisions to the original estimate of undiscounted cash flows (with corresponding adjustments to property, plant and equipment, net) and for accretion of the ARO liability due to the passage of time. The difference between the ARO liability, the corresponding ARO asset included in property, plant and equipment, net and amounts recovered in rates to satisfy such liabilities is recorded as a regulatory asset or liability on the Consolidated Balance Sheets. The costs are not recovered in rates until the work has been completed.

Impairment

Sierra Pacific evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or when the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value and any resulting impairment loss is reflected on the Consolidated Statements of Operations. As substantially all property, plant and equipment was used in regulated businesses, the impacts of regulation are considered when evaluating the carrying value of regulated assets.

Leases

Sierra Pacific has non-cancelable operating leases primarily for transmission and delivery assets, generating facilities, vehicles and office equipment and finance leases consisting primarily of transmission assets, generating facilities and vehicles. These leases generally require Sierra Pacific to pay for insurance, taxes and maintenance applicable to the leased property. Given the capital-intensive nature of the utility industry, it is common for a portion of lease costs to be capitalized when used during construction or maintenance of assets, in which the associated costs will be capitalized with the corresponding asset and depreciated over the remaining life of that asset. Certain leases contain renewal options for varying periods and escalation clauses for adjusting rent to reflect changes in price indices. Sierra Pacific does not include options in its lease calculations unless there is a triggering event indicating Sierra Pacific is reasonably certain to exercise the option. Sierra Pacific's accounting policy is to not recognize right-of-use assets and lease obligations for leases with contract terms of one year or less and not separate lease components from non-lease components and instead account for each separate lease component and the non-lease components associated with a lease as a single lease component. Leases will be evaluated for impairment in line with Accounting Standards Codification ("ASC") Topic 360, "Property, Plant and Equipment" when a triggering event has occurred that might affect the value and use of the assets being leased.

Sierra Pacific's leases of generating facilities generally are for the long-term purchase of electric energy, also known as power purchase agreements ("PPA"). PPAs are generally signed before or during the early stages of project construction and can yield a lease that has not yet commenced. These agreements are primarily for renewable energy and the payments are considered variable lease payments as they are based on the amount of output.

Sierra Pacific's operating and finance right-of-use assets are recorded in other assets and the operating and current finance lease liabilities are recorded in current and long-term other liabilities accordingly.

Revenue Recognition

Sierra Pacific uses a single five-step model to identify and recognize revenue from contracts with customers ("Customer Revenue") upon transfer of control of promised goods or services in an amount that reflects the consideration to which Sierra Pacific expects to be entitled in exchange for those goods or services. Sierra Pacific records sales, franchise and excise taxes collected directly from customers and remitted directly to the taxing authorities on a net basis on the Consolidated Statements of Operations.

Substantially all of Sierra Pacific's Customer Revenue is derived from tariff-based sales arrangements approved by various regulatory commissions. These tariff-based revenues are mainly comprised of energy, transmission, distribution and natural gas and have performance obligations to deliver energy products and services to customers which are satisfied over time as energy is delivered or services are provided. Other revenue consists primarily of revenue recognized in accordance with ASC 842, "Leases" and amounts not considered Customer Revenue within ASC 606, "Revenue from Contracts with Customers."

Revenue recognized is equal to what Sierra Pacific has the right to invoice as it corresponds directly with the value to the customer of Sierra Pacific's performance to date and includes billed and unbilled amounts. As of December 31, 2024 and 2023, trade receivables, net on the Consolidated Balance Sheets relate substantially to Customer Revenue, including unbilled revenue of \$84 million and \$95 million, respectively. Payments for amounts billed are generally due from the customer within 30 days of billing. Rates charged for energy products and services are established by regulators or contractual arrangements that establish the transaction price as well as the allocation of price amongst the separate performance obligations. When preliminary regulated rates are permitted to be billed prior to final approval by the applicable regulator, certain revenue collected may be subject to refund and a liability for estimated refunds is accrued.

Unamortized Debt Premiums, Discounts and Issuance Costs

Premiums, discounts and financing costs incurred for the issuance of long-term debt are amortized over the term of the related financing using the effective interest method.

Income Taxes

Berkshire Hathaway includes Sierra Pacific in its consolidated U.S. federal income tax return. Consistent with established regulatory practice, Sierra Pacific's provision for income taxes has been computed on a stand-alone basis.

Deferred income tax assets and liabilities are based on differences between the financial statement and income tax basis of assets and liabilities using enacted income tax rates expected to be in effect for the year in which the differences are expected to reverse. Changes in deferred income tax assets and liabilities associated with components of other comprehensive income ("OCI") are charged or credited directly to OCI. Changes in deferred income tax assets and liabilities associated with certain property-related basis differences and other various differences that Sierra Pacific deems probable to be passed on to its customers are charged or credited directly to a regulatory asset or liability and will be included in regulated rates when the temporary differences reverse. Other changes in deferred income tax assets and liabilities are included as a component of income tax expense. Changes in deferred income tax assets and liabilities attributable to changes in enacted income tax rates are charged or credited to income tax expense or a regulatory asset or liability in the period of enactment. Valuation allowances are established when necessary to reduce deferred income tax assets to the amount that is more-likely-than-not to be realized.

Investment tax credits are deferred and amortized over the estimated useful lives of the related properties.

Sierra Pacific recognizes the tax benefit from an uncertain tax position only if it is more-likely-than-not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the Consolidated Financial Statements from such a position are measured based on the largest benefit that is more-likely-than-not to be realized upon ultimate settlement. Sierra Pacific's unrecognized tax benefits are primarily included in other long-term liabilities on the Consolidated Balance Sheets. Estimated interest and penalties, if any, related to uncertain tax positions are included as a component of income tax expense (benefit) on the Consolidated Statements of Operations.

New Accounting Pronouncements

In November 2023, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2023-07, Segment Reporting Topic 280, "Segment Reporting—Improvements to Reportable Segment Disclosures" which allows disclosure of one or more measures of segment profit or loss used by the chief operating decision maker to allocate resources and assess performance. Additionally, the standard requires enhanced disclosures of significant segment expenses and other segment items as well as incremental qualitative disclosures on both an annual and interim basis. This guidance is effective for annual reporting periods beginning after December 15, 2023, and interim reporting periods after December 15, 2024. Early adoption is permitted and retrospective application is required for all periods presented. Sierra Pacific adopted this guidance for the fiscal year beginning January 1, 2024 under the retrospective method. The adoption did not have a material impact on Sierra Pacific's Consolidated Financial Statements but did increase the disclosures included within Notes to Consolidated Financial Statements. Refer to Note 18 for additional disclosures of certain significant segment expenses.

In December 2023, the FASB issued ASU No. 2023-09, Income Taxes Topic 740, "Income Tax—Improvements to Income Tax Disclosures" which requires enhanced disclosures, including specific categories and disaggregation of information in the effective tax rate reconciliation, disaggregated information related to income taxes paid, income or loss from continuing operations before income tax expense or benefit, and income tax expense or benefit from continuing operations. This guidance is effective for annual reporting periods beginning after December 15, 2024. Early adoption is permitted and should be applied on a prospective basis, however retrospective application is permitted. Sierra Pacific is currently evaluating the impact of adopting this guidance on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

In November 2024, the FASB issued ASU No. 2024-03, Income Statement—Reporting Comprehensive Income—Expense Disaggregation Disclosures Subtopic 220-40, "Disaggregation of Income Statement Expenses" which addresses requests from investors for more detailed information about certain expenses and requires disclosure of the amounts of purchases of inventory, employee compensation, depreciation and intangible asset amortization included in each relevant expense caption presented on the income statement. This guidance is effective for annual reporting periods beginning after December 15, 2026 and interim reporting periods beginning after December 15, 2027. Early adoption is permitted and should be applied on a prospective basis, however retrospective application is permitted. Sierra Pacific is currently evaluating the impact of adopting this guidance on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

(3) Property, Plant and Equipment, Net

Property, plant and equipment, net consists of the following as of December 31 (in millions):

	Depreciable Life	2024	2023
Utility plant:			
Generation	25 - 70 years	\$ 1,339	\$ 1,313
Transmission	50 - 76 years	1,071	1,023
Electric distribution	20 - 76 years	2,224	2,074
Electric intangible plant and other	5 - 65 years	254	247
Natural gas distribution	35 - 70 years	563	537
Natural gas intangible plant and other	5 - 65 years	18	17
Common other	5 - 65 years	377	376
Utility plant		5,846	5,587
Accumulated depreciation and amortization		(2,208)	(2,091)
		3,638	3,496
Construction work-in-progress		801	326
Property, plant and equipment, net		<u>\$ 4,439</u>	<u>\$ 3,822</u>

All of Sierra Pacific's plant is subject to the ratemaking jurisdiction of the PUCN and the FERC. Sierra Pacific's depreciation and amortization expense, as authorized by the PUCN, stated as a percentage of the depreciable property balances as of December 31, 2024, 2023 and 2022 was 3.1%, 3.3% and 3.0%, respectively. Sierra Pacific is required to file a utility plant depreciation study every six years as a companion filing with the triennial general rate review filings. The most recent study was filed in 2022 and the approved rates were effective January 1, 2023.

Construction work-in-progress is primarily related to the construction of regulated assets.

(4) Jointly Owned Utility Facilities

Under joint facility ownership agreements, Sierra Pacific, as tenants in common, has undivided interests in jointly owned generation and transmission facilities. Sierra Pacific accounts for its proportionate share of each facility and each joint owner has provided financing for its share of each facility. Operating costs of each facility are assigned to joint owners based on their percentage of ownership or energy production, depending on the nature of the cost. Operating costs and expenses on the Consolidated Statements of Operations include Sierra Pacific's share of the expenses of these facilities.

The amounts shown in the table below represent Sierra Pacific's share in each jointly owned facility included in property, plant and equipment, net as of December 31, 2024 (dollars in millions):

	Sierra Pacific's Share	Utility Plant	Accumulated Depreciation	Construction Work-in- Progress
Valmy Nos. 1 and 2	50 %	\$ 412	\$ 372	\$ 13
ON Line Transmission Line	6	40	10	—
Valmy Transmission	50	4	2	32
Total		<u>\$ 456</u>	<u>\$ 384</u>	<u>\$ 45</u>

(5) Leases

The following table summarizes Sierra Pacific's leases recorded on the Consolidated Balance Sheet as of December 31 (in millions):

	2024	2023
Right-of-use assets:		
Operating leases	\$ 15	\$ 16
Finance leases	99	100
Total right-of-use assets	<u>\$ 114</u>	<u>\$ 116</u>
Lease liabilities:		
Operating leases	\$ 15	\$ 15
Finance leases	102	103
Total lease liabilities	<u>\$ 117</u>	<u>\$ 118</u>

The following table summarizes Sierra Pacific's lease costs for the years ended December 31 (in millions):

	2024	2023	2022
Variable	\$ 100	\$ 99	\$ 103
Operating	2	2	1
Finance:			
Amortization	5	5	5
Interest	8	8	8
Total lease costs	<u>\$ 115</u>	<u>\$ 114</u>	<u>\$ 117</u>
Weighted-average remaining lease term (years):			
Operating leases	23.8	24.6	26.0
Finance leases	26.2	27.6	28.2
Weighted-average discount rate:			
Operating leases	5.0 %	5.0 %	5.0 %
Finance leases	8.4 %	8.4 %	8.4 %

The following table summarizes Sierra Pacific's supplemental cash flow information relating to leases for the years ended December 31 (in millions):

	2024	2023	2022
Cash paid for amounts included in the measurement of lease liabilities:			
Operating cash flows from operating leases	\$ (2)	\$ (2)	\$ (1)
Operating cash flows from finance leases	(8)	(8)	(9)
Financing cash flows from finance leases	(8)	(7)	(7)
Right-of-use assets obtained in exchange for lease liabilities:			
Operating leases	\$ 1	\$ 1	1
Finance leases	5	3	1

Sierra Pacific has the following remaining lease commitments as of December 31, 2024 (in millions):

	Operating	Finance	Total
2025	\$ 1	\$ 17	\$ 18
2026	1	16	17
2027	1	14	15
2028	1	13	14
2029	1	9	10
Thereafter	22	124	146
Total undiscounted lease payments	27	193	220
Less - amounts representing interest	(12)	(91)	(103)
Lease liabilities	<u>\$ 15</u>	<u>\$ 102</u>	<u>\$ 117</u>

Operating and Finance Lease Obligations

Sierra Pacific's operating and finance lease obligations consist mainly of ON Line and Truckee-Carson Irrigation District ("TCID"). ON Line was placed in-service on December 31, 2013. Sierra Pacific and Nevada Power, collectively the ("Nevada Utilities"), entered into a long-term transmission use agreement, in which the Nevada Utilities have a 25% interest and Great Basin Transmission South, LLC has a 75% interest. The Nevada Utilities' share of the long-term transmission use agreement and ownership interest is split at 75% for Nevada Power and 25% for Sierra Pacific. The term of the lease is 41 years with the agreement ending December 31, 2054. In 1999, Sierra Pacific entered into a 50-year agreement with TCID to lease electric distribution facilities. Total finance lease obligations of \$114 million and \$117 million were included on the Consolidated Balance Sheets as of December 31, 2024 and 2023, respectively, for these leases. See Note 2 for further discussion of Sierra Pacific's remaining lease obligations.

(6) Regulatory Matters

Regulatory Assets

Regulatory assets represent costs that are expected to be recovered in future rates. Sierra Pacific's regulatory assets reflected on the Consolidated Balance Sheets consist of the following as of December 31 (in millions):

	Weighted Average Remaining Life	2024	2023
Natural disaster protection plan	1 year	\$ 90	\$ 78
Deferred energy costs	N/A	—	77
Merger costs from 1999 merger	22 years	57	60
Employee benefit plans ⁽¹⁾	7 years	45	48
Deferred operating costs	4 years	16	25
Other	Various	84	93
Total regulatory assets		\$ 292	\$ 381
Reflected as:			
Current assets		\$ 90	\$ 161
Noncurrent assets		202	220
Total regulatory assets		\$ 292	\$ 381

- (1) Represents amounts not yet recognized as a component of net periodic benefit cost that are expected to be included in regulated rates when recognized.

Sierra Pacific had regulatory assets not earning a return on investment of \$131 million and \$132 million as of December 31, 2024 and 2023, respectively. The regulatory assets not earning a return on investment primarily consist of merger costs from the 1999 merger, a portion of the employee benefit plans, unrealized losses on regulated derivative contracts, AROs and losses on reacquired debt.

Regulatory Liabilities

Regulatory liabilities represent amounts that are expected to be returned to customers in future periods. Sierra Pacific's regulatory liabilities reflected on the Consolidated Balance Sheets consist of the following as of December 31 (in millions):

	Weighted Average Remaining Life	2024	2023
Deferred income taxes ⁽¹⁾	Various	\$ 193	\$ 206
Cost of removal ⁽²⁾	31 years	216	211
Deferred energy costs	1 year	86	—
Other	Various	27	22
Total regulatory liabilities		\$ 522	\$ 439
Reflected as:			
Current liabilities		\$ 106	\$ 15
Noncurrent liabilities		416	424
Total regulatory liabilities		\$ 522	\$ 439

- (1) Amounts primarily represent income tax liabilities related to the federal tax rate change from 35% to 21% that are probable to be passed on to customers, offset by income tax benefits related to accelerated tax depreciation and certain property-related basis differences and other various differences that were previously passed on to customers and will be included in regulated rates when the temporary differences reverse.
- (2) Amounts represent estimated costs, as accrued through depreciation rates and exclusive of ARO liabilities, of removing regulated property, plant and equipment in accordance with accepted regulatory practices.

Deferred Energy

Nevada statutes permit regulated utilities to adopt deferred energy accounting procedures. The intent of these procedures is to ease the effect on customers of fluctuations in the cost of purchased natural gas, fuel and electricity and are subject to annual prudence review by the PUCN. Under deferred energy accounting, to the extent actual fuel and purchased power costs exceed fuel and purchased power costs recoverable through current rates that excess is not recorded as a current expense on the Consolidated Statements of Operations but rather is deferred and recorded as a regulatory asset on the Consolidated Balance Sheets and would be included in the regulatory assets table above as deferred energy costs. Conversely, a regulatory liability is recorded to the extent fuel and purchased power costs recoverable through current rates exceed actual fuel and purchased power costs and is included in the regulatory liabilities table above as deferred energy costs. These excess amounts are reflected in quarterly adjustments to rates and recorded as cost of fuel, energy and capacity in future time periods.

Regulatory Rate Review

In February 2024, Sierra Pacific filed electric and gas regulatory rate reviews with the PUCN that requested annual revenue increases of \$95 million, or 8.8% and \$11 million, or 4.9%, respectively. Sierra Pacific filed the certification filing that updated the electric and gas filings to requested annual revenue increases of \$96 million, or 9.5% and \$12 million, or 6.4%, respectively. Hearings in the cost of capital phase were held in June 2024 and the hearings for the revenue requirement phase were held in July 2024. The hearings in the rate design phase were held in August 2024. In September 2024, the PUCN issued an order approving an increase in base rates for electric of \$40 million and for gas of \$8 million. In October 2024, Sierra Pacific filed a petition for reconsideration and clarification of the order. In November 2024, the PUCN issued a final order approving in part and denying in part the petition for reconsideration.

In January 2025, Sierra Pacific filed an application for approval of the establishment and associated cost recovery of a Wildfire Self-Insurance Policy. In the application, Sierra Pacific request first, that the PUCN issue an order determining that it is reasonable and prudent for the Nevada Utilities to establish a \$500 million wildfire self-insurance policy (the "Policy") in order to have additional wildfire liability insurance in place in the event that a catastrophic wildfire in Nevada is alleged to be caused or exacerbated by utility equipment. The Policy would provide \$500 million in additional coverage for the Nevada Utilities for third-party claims, and it would be in excess to the commercial wildfire liability insurance that the Nevada Utilities currently possess. Second, the application requests approval for the collection of the costs for the Policy in rates over a ten-year period. An order is expected in 2025.

(7) Short-term Debt and Credit Facilities

Sierra Pacific has a \$400 million secured credit facility expiring in June 2027 with an unlimited number of maturity extension options, subject to lender consent. The credit facility, which is for general corporate purposes and provides for the issuance of letters of credit, has a variable interest rate based on the Secured Overnight Financing Rate or a base rate, at Sierra Pacific's option, plus a spread that varies based on Sierra Pacific's credit ratings for its senior secured long-term debt securities. As of December 31, 2024 and 2023, Sierra Pacific had no borrowings outstanding under the credit facility. Amounts due under Sierra Pacific's credit facility are collateralized by Sierra Pacific's general and refunding mortgage bonds. The credit facility requires Sierra Pacific's ratio of debt, including current maturities, to total capitalization not exceed 0.65 to 1.0 as of the last day of each quarter.

As of December 31, 2024 and 2023, Sierra Pacific had \$50 million, respectively, of letter of credit capacity under its \$400 million secured credit facility, of which no amount was outstanding.

(8) Long-term Debt

Sierra Pacific's long-term debt consists of the following, including unamortized premiums, discounts and debt issuance costs, as of December 31 (dollars in millions):

	Par Value	2024	2023
General and refunding mortgage securities:			
2.60% Series U, due 2026	\$ 400	\$ 399	\$ 398
6.75% Series P, due 2037	252	254	254
4.71% Series W, due 2052	250	248	248
5.90% Series 2023A, due 2054	400	394	393
Tax-exempt refunding revenue bond obligations:			
Fixed-rate series:			
3.55% Pollution Control Series 2016A, due 2029	\$ 20	\$ 20	\$ —
3.55% Pollution Control Series 2016B, due 2029 ⁽¹⁾	30	29	—
3.625% Gas and Water Series 2016B, due 2036 ⁽²⁾	60	59	—
4.125% Water Facilities Series 2016C, due 2036 ⁽²⁾	30	30	—
4.125% Water Facilities Series 2016F, due 2036 ⁽²⁾	75	74	—
3.625% Water Facilities Series 2016G, due 2036 ⁽²⁾	20	20	—
Total long-term debt	<u>\$ 1,537</u>	<u>\$ 1,527</u>	<u>\$ 1,293</u>

Reflected as:

Total long-term debt	<u>\$ 1,527</u>	<u>\$ 1,293</u>

(1) Subject to mandatory sinking fund redemption by Sierra Pacific in the principal amount of \$10 million in April 2026.

(2) Subject to mandatory purchase by Sierra Pacific in October 2029 at which date the interest rate may be adjusted.

Annual Payment on Long-Term Debt

The annual repayments of long-term debt for the years beginning January 1, 2025 and thereafter, are as follows (in millions):

	Long-term Debt
2026	\$ 410
2029 and thereafter	1,127
Total	1,537
Unamortized premium, discount and debt issuance cost	(10)
Total	<u>\$ 1,527</u>

The issuance of General and Refunding Mortgage Securities by Sierra Pacific is subject to PUCN approval and is limited by available property and other provisions of the mortgage indentures. As of December 31, 2024, approximately \$5.2 billion (based on original cost) of Sierra Pacific's property was subject to the liens of the mortgages.

(9) Income Taxes

Income tax expense consists of the following for the years ended December 31 (in millions):

	<u>2024</u>	<u>2023</u>	<u>2022</u>
Current – Federal	\$ 59	\$ 72	\$ (12)
Deferred – Federal	(49)	(57)	31
Investment tax credits	—	1	—
Total income tax expense	<u>\$ 10</u>	<u>\$ 16</u>	<u>\$ 19</u>

A reconciliation of the federal statutory income rate to the effective income tax rate applicable to income before income tax expense is as follows for the years ended December 31:

	<u>2024</u>	<u>2023</u>	<u>2022</u>
Federal statutory income tax rate	21 %	21 %	21 %
Effects of ratemaking	(11)	(9)	(7)
Other	1	—	—
Effective income tax rate	<u>11 %</u>	<u>12 %</u>	<u>14 %</u>

Effects of ratemaking is primarily attributable to the recognition of excess deferred income taxes related to the federal tax rate change from 35% to 21% pursuant to an order issued by the PUCN effective January 1, 2020.

The net deferred income tax liability consists of the following as of December 31 (in millions):

	<u>2024</u>	<u>2023</u>
Deferred income tax assets:		
Regulatory liabilities	\$ 60	\$ 62
Operating and finance leases	24	25
Customer advances	24	16
Unamortized contract value	3	3
Other	7	5
Total deferred income tax assets	<u>118</u>	<u>111</u>
Deferred income tax liabilities:		
Property-related items	(379)	(376)
Regulatory assets	(68)	(100)
Operating and finance leases	(24)	(24)
Other	(16)	(15)
Total deferred income tax liabilities	<u>(487)</u>	<u>(515)</u>
Net deferred income tax liability	<u>\$ (369)</u>	<u>\$ (404)</u>

The U.S. Internal Revenue Service has closed or effectively settled its examination of Sierra Pacific's income tax return through the short year ended December 31, 2013. The closure of examinations, or the expiration of the statute of limitations, may not preclude the U.S. Internal Revenue Service from adjusting the federal net operating loss carryforward utilized in a year for which the statute of limitations is not closed.

(10) Employee Benefit Plans

Sierra Pacific is a participant in benefit plans sponsored by NV Energy. The NV Energy Retirement Plan includes a qualified pension plan ("Qualified Pension Plan") and a supplemental executive retirement plan and a restoration plan (collectively, "Non-Qualified Pension Plans") that provide pension benefits for eligible employees. The NV Energy Comprehensive Welfare Benefit and Cafeteria Plan provides certain postretirement health care and life insurance benefits for eligible retirees ("Other Postretirement Plans") on behalf of Sierra Pacific. Sierra Pacific did not make any contributions to the Qualified Pension Plan for the years ended December 31, 2024, 2023 and 2022. Sierra Pacific contributed \$1 million to the Non-Qualified Pension Plans for the years ended December 31, 2024, 2023 and 2022. Sierra Pacific contributed \$3 million, \$3 million, and \$5 million to the Other Post Retirement Plans for the years ended December 31, 2024, 2023, and 2022 respectively. Amounts attributable to Sierra Pacific were allocated from NV Energy based upon the current, or in the case of retirees, previous, employment location. Offsetting regulatory assets and liabilities have been recorded related to the amounts not yet recognized as a component of net periodic benefit costs that will be included in regulated rates. Net periodic benefit costs not included in regulated rates are included in accumulated other comprehensive loss, net.

Amounts receivable from (payable to) NV Energy are included on the Consolidated Balance Sheets and consist of the following as of December 31 (in millions):

	2024	2023
Qualified Pension Plan -		
Other non-current assets	\$ 59	\$ 53
Non-Qualified Pension Plans:		
Other current liabilities	(1)	(1)
Other long-term liabilities	(5)	(5)
Other Postretirement Plans:		
Other non-current assets	5	1

(11) Asset Retirement Obligations

Sierra Pacific estimates its ARO liabilities based upon detailed engineering calculations of the amount and timing of the future cash spending for a third party to perform the required work. Spending estimates are escalated for inflation and then discounted at a credit-adjusted, risk-free rate. Changes in estimates could occur for a number of reasons, including changes in laws and regulations, plan revisions, inflation and changes in the amount and timing of the expected work.

Sierra Pacific does not recognize liabilities for AROs for which the fair value cannot be reasonably estimated. Due to the indeterminate removal date, the fair value of the associated liabilities on certain generation, transmission, distribution and other assets cannot currently be estimated, and no amounts are recognized on the Consolidated Financial Statements other than those included in the cost of removal regulatory liability established via approved depreciation rates in accordance with accepted regulatory practices. These accruals totaled \$216 million and \$211 million as of December 31, 2024 and 2023, respectively.

The following table presents Sierra Pacific's ARO liabilities by asset type as of December 31 (in millions):

	2024	2023
Asbestos	\$ 5	\$ 5
Evaporative ponds and dry ash landfills	2	3
Solar-powered generating facilities	1	1
Other	3	3
Total asset retirement obligations	<u>\$ 11</u>	<u>\$ 12</u>

The following table reconciles the beginning and ending balances of Sierra Pacific's ARO liabilities for the years ended December 31 (in millions):

	2024	2023
Beginning balance	\$ 12	\$ 11
Change in estimated costs	(2)	—
Additions	—	1
Accretion	1	—
Ending balance	<u>\$ 11</u>	<u>\$ 12</u>
Reflected as -		
Other long-term liabilities	<u>\$ 11</u>	<u>\$ 12</u>

Certain of Sierra Pacific's decommissioning and reclamation obligations relate to jointly-owned facilities, and as such, Sierra Pacific is committed to pay a proportionate share of the decommissioning or reclamation costs. In the event of a default by any of the other joint participants, the respective subsidiary may be obligated to absorb, directly or by paying additional sums to the entity, a proportionate share of the defaulting party's liability. Sierra Pacific's estimated share of the decommissioning and reclamation obligations are primarily recorded as ARO liabilities in other long-term liabilities on the Consolidated Balance Sheets.

In May 2024, the United States Environmental Protection Agency published its final rule on legacy coal combustion residuals ("CCR") surface impoundments and CCR management units ("CCRMUs") in the Federal Register. CCRMUs include CCR surface impoundments and landfills closed before October 19, 2015 and inactive CCR landfills. The final rule contains three main components: (1) a definition for legacy CCR surface impoundments, which are inactive surface impoundments at inactive generating facilities that must adhere to the same regulations as inactive CCR impoundments at active generating facilities, barring location restrictions and liner design criteria, with customized compliance deadlines; (2) groundwater monitoring, corrective action, closure, and post closure care requirements for CCRMUs, which may be located at active generating facilities and inactive generating facilities with a legacy CCR surface impoundment; and (3) the owners and operators of inactive generating facilities must identify the presence of legacy CCR surface impoundments and comply with all rule requirements for surface impoundments; and the owners and operators of active generating facilities and inactive generating facilities with a legacy CCR surface impoundment must prepare Facility Evaluation Reports ("FERs") that identify and describe the CCRMUs and determine whether closure is required. In a manner consistent with existing CCR rules, owners and operators must publish FERs on their CCR websites in two parts, within 15 months (Part 1) and 27 months (Part 2) of the final rule's effective date in November 2024. Sierra Pacific is currently evaluating the final rule and does not anticipate identifying any legacy surface impoundments, but does anticipate that it may identify CCRMUs subject to the rule. Due to the number of site investigations warranted by this rule and the nature of engineering and other studies required at each site, Sierra Pacific is unable to reasonably estimate the potential impact, which may be material, to its asset retirement obligations.

(12) Risk Management and Hedging Activities

Sierra Pacific is exposed to the impact of market fluctuations in commodity prices and interest rates. Sierra Pacific is principally exposed to electricity, natural gas and coal market fluctuations primarily through Sierra Pacific's obligation to serve retail customer load in its regulated service territory. Sierra Pacific's load and generating facilities represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel required to generate electricity and wholesale electricity that is purchased and sold. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather, market liquidity, generating facility availability, customer usage, storage, and transmission and transportation constraints. The actual cost of fuel and purchased power is recoverable through the deferred energy mechanism. Interest rate risk exists on variable-rate debt and future debt issuances. Sierra Pacific does not engage in proprietary trading activities.

Sierra Pacific has established a risk management process that is designed to identify, assess, manage and report on each of the various types of risk involved in its business. To mitigate a portion of its commodity price risk, Sierra Pacific uses commodity derivative contracts, which may include forwards, futures, options, swaps and other agreements, to effectively secure future supply or sell future production generally at fixed prices. Sierra Pacific manages its interest rate risk by limiting its exposure to variable interest rates primarily through the issuance of fixed-rate long-term debt and by monitoring market changes in interest rates. Additionally, Sierra Pacific may from time to time enter into interest rate derivative contracts, such as interest rate swaps or locks, to mitigate Sierra Pacific's exposure to interest rate risk. Sierra Pacific does not hedge all of its commodity price and interest rate risks, thereby exposing the unhedged portion to changes in market prices.

There have been no significant changes in Sierra Pacific's accounting policies related to derivatives. Refer to Notes 2 and 13 for additional information on derivative contracts.

The following table, which excludes contracts that have been designated as normal under the normal purchases and normal sales exception afforded by GAAP, summarizes the fair value of Sierra Pacific's derivative contracts, on a gross basis, and reconciles those amounts presented on a net basis on the Consolidated Balance Sheets (in millions):

	Other Long-Term Assets	Other Current Liabilities	Other Long-term Liabilities	Total
As of December 31, 2024:				
Not designated as hedging contracts ⁽¹⁾:				
Commodity assets	\$ 1	\$ —	\$ —	\$ 1
Commodity liabilities	—	(14)	—	(14)
Total derivative - net basis	<u>\$ 1</u>	<u>\$ (14)</u>	<u>\$ —</u>	<u>\$ (13)</u>
As of December 31, 2023:				
Not designated as hedging contracts ⁽¹⁾ -				
Commodity liabilities	<u>\$ —</u>	<u>\$ (16)</u>	<u>\$ —</u>	<u>\$ (16)</u>

- (1) Sierra Pacific's commodity derivatives not designated as hedging contracts are included in regulated rates. As of December 31, 2024 and 2023, a regulatory asset of \$13 million and \$16 million, respectively, was recorded related to the net derivative liability of \$13 million and \$16 million, respectively.

Derivative Contract Volumes

The following table summarizes the net notional amounts of outstanding commodity derivative contracts with fixed price terms that comprise the mark-to-market values as of December 31 (in millions):

	Unit of Measure	2024	2023
Electricity purchases	Megawatt hours	1	—
Natural gas purchases	Decatherms	57	55

Credit Risk

Sierra Pacific is exposed to counterparty credit risk associated with wholesale energy supply and marketing activities with other utilities, energy marketing companies, financial institutions and other market participants. Credit risk may be concentrated to the extent Sierra Pacific's counterparties have similar economic, industry or other characteristics and due to direct and indirect relationships among the counterparties. Before entering into a transaction, Sierra Pacific analyzes the financial condition of each significant wholesale counterparty, establishes limits on the amount of unsecured credit to be extended to each counterparty and evaluates the appropriateness of unsecured credit limits on an ongoing basis. To further mitigate wholesale counterparty credit risk, Sierra Pacific enters into netting and collateral arrangements that may include margining and cross-product netting agreements and obtain third-party guarantees, letters of credit and cash deposits. If required, Sierra Pacific exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

In accordance with industry practice, certain wholesale agreements, including derivative contracts, contain credit support provisions that in part base certain collateral requirements on credit ratings for senior unsecured debt as reported by one or more of the recognized credit rating agencies. These agreements may either specifically provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed specified rating-dependent threshold levels ("credit-risk-related contingent features") or provide the right for counterparties to demand "adequate assurance" if there is a material adverse change in Sierra Pacific's creditworthiness. These rights can vary by contract and by counterparty. As of December 31, 2024, Sierra Pacific's credit ratings for its senior secured debt and its issuer credit ratings for senior unsecured debt from the recognized credit rating agencies were investment grade.

The aggregate fair value of Sierra Pacific's derivative contracts in liability positions with specific credit-risk-related contingent features totaled \$— million and \$1 million as of December 31, 2024 and 2023, respectively, which represents the amount of collateral to be posted if all credit risk related contingent features for derivative contracts in liability positions had been triggered. Sierra Pacific's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation or other factors.

(13) Fair Value Measurements

The carrying value of Sierra Pacific's cash, certain cash equivalents, receivables, payables, accrued liabilities and short-term borrowings approximates fair value because of the short-term maturity of these instruments. Sierra Pacific has various financial assets and liabilities that are measured at fair value on the Consolidated Balance Sheets using inputs from the three levels of the fair value hierarchy. A financial asset or liability classification within the hierarchy is determined based on the lowest level input that is significant to the fair value measurement. The three levels are as follows:

- Level 1 - Inputs are unadjusted quoted prices in active markets for identical assets or liabilities that Sierra Pacific has the ability to access at the measurement date.
- Level 2 - Inputs include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived principally from or corroborated by observable market data by correlation or other means (market corroborated inputs).
- Level 3 - Unobservable inputs reflect Sierra Pacific's judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. Sierra Pacific develops these inputs based on the best information available, including its own data.

The following table presents Sierra Pacific's financial assets and liabilities recognized on the Consolidated Balance Sheets and measured at fair value on a recurring basis (in millions):

	Input Levels for Fair Value Measurements			
	Level 1	Level 2	Level 3	Total
As of December 31, 2024:				
Assets:				
Commodity derivatives	\$ —	\$ —	\$ 1	\$ 1
Money market mutual funds	12	—	—	12
Investment funds	1	—	—	1
	<u>\$ 13</u>	<u>\$ —</u>	<u>\$ 1</u>	<u>\$ 14</u>
Liabilities - commodity derivatives	<u>\$ —</u>	<u>\$ —</u>	<u>\$ (14)</u>	<u>\$ (14)</u>
As of December 31, 2023:				
Assets:				
Money market mutual funds	\$ 41	\$ —	\$ —	\$ 41
Investment funds	1	—	—	1
	<u>\$ 42</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 42</u>
Liabilities - commodity derivatives	<u>\$ —</u>	<u>\$ —</u>	<u>\$ (16)</u>	<u>\$ (16)</u>

Sierra Pacific's investments in money market mutual funds and investment funds are accounted for as available-for-sale securities and are stated at fair value. When available, a readily observable quoted market price or net asset value of an identical security in an active market is used to record the fair value.

Derivative contracts are recorded on the Consolidated Balance Sheets as either assets or liabilities and are stated at estimated fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by GAAP. When available, the fair value of derivative contracts is estimated using unadjusted quoted prices for identical contracts in the market in which Sierra Pacific transacts. When quoted prices for identical contracts are not available, Sierra Pacific uses forward price curves. Forward price curves represent Sierra Pacific's estimates of the prices at which a buyer or seller could contract today for delivery or settlement at future dates. Sierra Pacific bases its forward price curves upon internally developed models, with internal and external fundamental data inputs. Market price quotations for certain electricity and natural gas trading hubs are not as readily obtainable due to markets that are not active. Given that limited market data exists for these contracts, Sierra Pacific uses forward price curves derived from internal models based on perceived pricing relationships to major trading hubs that are based on unobservable inputs. The model incorporates a mid-market pricing convention (the mid-point price between bid and ask prices) as a practical expedient for valuing its assets and liabilities measured and reported at fair value. The determination of the fair value for derivative contracts not only includes counterparty risk, but also the impact of Sierra Pacific's nonperformance risk on its liabilities, which as of December 31, 2024, had an immaterial impact to the fair value of its derivative contracts. As such, Sierra Pacific considers its derivative contracts to be valued using Level 3 inputs.

The following table reconciles the beginning and ending balances of Sierra Pacific's net commodity derivative assets or liabilities measured at fair value on a recurring basis using significant Level 3 inputs for the years ended December 31 (in millions):

	2024	2023	2022
Beginning balance	\$ (16)	\$ (13)	\$ (33)
Changes in fair value recognized in regulatory assets or liabilities	(27)	(50)	(21)
Settlements	30	47	41
Ending balance	<u>\$ (13)</u>	<u>\$ (16)</u>	<u>\$ (13)</u>

Sierra Pacific's long-term debt is carried at cost on the Consolidated Balance Sheets. The fair value of Sierra Pacific's long-term debt is a Level 2 fair value measurement and has been estimated based upon quoted market prices, where available, or at the present value of future cash flows discounted at rates consistent with comparable maturities with similar credit risks. The following table presents the carrying value and estimated fair value of Sierra Pacific's long-term debt as of December 31 (in millions):

	2024		2023	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	\$ 1,527	\$ 1,506	\$ 1,293	\$ 1,311

(14) Commitments and Contingencies

Commitments

Sierra Pacific has the following firm commitments that are not reflected on the Consolidated Balance Sheet. Minimum payments as of December 31, 2024 are as follows (in millions):

	2025	2026	2027	2028	2029	2030 and Thereafter	Total
Contract type:							
Purchased electricity contracts - commercially operable	\$ 119	\$ 120	\$ 112	\$ 106	\$ 97	\$ 1,370	\$ 1,924
Purchased electricity contracts - non-commercially operable	9	25	41	54	63	2,773	2,965
Fuel contracts	67	54	27	27	26	58	259
Construction commitments	1,224	784	401	117	17	—	2,543
Transmission	28	4	5	—	—	—	37
Easements	2	2	2	1	2	30	39
Maintenance, service and other contracts	12	16	14	1	1	2	46
Total commitments	\$ 1,461	\$ 1,005	\$ 602	\$ 306	\$ 206	\$ 4,233	\$ 7,813

Purchased Electricity Contracts - Commercially Operable

Sierra Pacific has several contracts for long-term purchase of electric energy which have been approved by the PUCN. The expiration of these contracts range from 2026 to 2048. Purchased power includes estimated payments for contracts which meet the definition of a lease and payments are based on the amount of energy expected to be generated. See Note 5 for further discussion of Sierra Pacific's lease commitments.

Purchased Electricity Contracts - Non-Commercially Operable

Sierra Pacific has several contracts for long-term purchase of electric energy in which the facility remains under development. Amounts represent the estimated payments under renewable energy power purchase contracts, which have been approved by the PUCN and are contingent upon the developers obtaining commercial operation and their ability to deliver power.

Fuel Contracts

Sierra Pacific has a long-term contract for the transport of coal that expires in 2025. Additionally, gas transportation contracts expire from 2023 to 2046.

Construction Commitments

Sierra Pacific's construction commitments included in the table above relate to firm commitments and include costs associated with a 400-MW solar photovoltaic facility with an additional 400-MWs of co-located battery storage that is being developed in Churchill County, Nevada, with ownership share approved by the PUCN of 90% Sierra Pacific and 10% Nevada Power, the repower project at the Valmy generating station to convert existing coal-fired combustion to natural gas-fire combustion, a hydrogen-capable natural gas simple cycle combustion turbine peakers project at the Valmy generating station, the Greenlink Nevada transmission expansion project that is being developed in western and northern Nevada and certain other generation plant projects.

Transmission

Sierra Pacific has contracts for the right to transmit electricity over other entities' transmission lines to facilitate delivery to Sierra Pacific's customers.

Easements

Sierra Pacific has non-cancelable easements for land. Operating and maintenance expense on non-cancelable easements totaled \$2 million for the years ended December 31, 2024, 2023 and 2022.

Maintenance, Service and Other Contracts

Sierra Pacific has long-term service agreements for the performance of maintenance on generation units. Obligation amounts are based on estimated usage. The estimated expiration of these service agreements range from 2026 to 2029.

Environmental Laws and Regulations

Sierra Pacific is subject to federal, state and local laws and regulations regarding air quality, climate change, emissions performance standards, water quality, coal ash disposal and other environmental matters that have the potential to impact its current and future operations. Sierra Pacific believes it is in material compliance with all applicable laws and regulations.

Legal Matters

Sierra Pacific is party to a variety of legal actions arising out of the normal course of business. Sierra Pacific does not believe that such normal and routine litigation will have a material impact on its financial results.

(15) Revenues from Contracts with Customers

The following table summarizes Sierra Pacific's Customer Revenue by customer class, including a reconciliation to Sierra Pacific's reportable segment information included in Note 18, for the years ended December 31 (in millions):

	2024			2023			2022		
	Electric	Natural Gas	Total	Electric	Natural Gas	Total	Electric	Natural Gas	Total
Customer Revenue:									
Retail:									
Residential	\$ 388	\$ 114	\$ 502	\$ 421	\$ 143	\$ 564	\$ 365	\$ 105	\$ 470
Commercial	349	47	396	385	64	449	333	45	378
Industrial	264	19	283	299	27	326	229	16	245
Other	4	1	5	5	1	6	6	1	7
Total fully bundled	1,005	181	1,186	1,110	235	1,345	933	167	1,100
Distribution only service	6	—	6	5	—	5	5	—	5
Total retail	1,011	181	1,192	1,115	235	1,350	938	167	1,105
Wholesale, transmission and other	68	—	68	78	—	78	86	—	86
Total Customer Revenue	1,079	181	1,260	1,193	235	1,428	1,024	167	1,191
Other revenue	1	1	2	1	2	3	1	1	2
Total operating revenue	<u>\$ 1,080</u>	<u>\$ 182</u>	<u>\$ 1,262</u>	<u>\$ 1,194</u>	<u>\$ 237</u>	<u>\$ 1,431</u>	<u>\$ 1,025</u>	<u>\$ 168</u>	<u>\$ 1,193</u>

(16) Supplemental Cash Flow Disclosures

The summary of supplemental cash flow disclosures as of and for the years ended December 31 is as follows (in millions):

	2024	2023	2022
Supplemental disclosure of cash flow information:			
Interest paid, net of amounts capitalized	<u>\$ 72</u>	<u>\$ 49</u>	<u>\$ 45</u>
Income taxes paid (refunded)	<u>\$ 66</u>	<u>\$ 56</u>	<u>\$ (1)</u>
Supplemental disclosure of non-cash investing and financing transactions:			
Accruals related to property, plant and equipment additions	<u>\$ 133</u>	<u>\$ 51</u>	<u>\$ 57</u>

(17) Related Party Transactions

Sierra Pacific has an intercompany administrative services agreement with BHE and its subsidiaries. Amounts charged to Sierra Pacific under this agreement, either directly or through NV Energy, totaled \$45 million, \$27 million and \$23 million for the years ended December 31, 2024, 2023 and 2022. Amounts charged to Sierra Pacific in 2024 and 2023 primarily relate to information technology projects billed at a consolidated level and passed through to affiliates.

Sierra Pacific provided electricity to Nevada Power of \$29 million, \$70 million and \$86 million for the years ended December 31, 2024, 2023 and 2022, respectively. Receivables associated with these transactions were \$1 million as of December 31, 2024 and 2023. Sierra Pacific purchased electricity from Nevada Power of \$188 million, \$230 million and \$362 million for the years ended December 31, 2024, 2023 and 2022, respectively. Payables associated with these transactions were \$7 million and \$10 million as of December 31, 2024 and 2023, respectively.

Sierra Pacific incurs intercompany administrative and shared facility costs with NV Energy and Nevada Power. These transactions are governed by an intercompany service agreement and are priced at cost. NV Energy provided services to Sierra Pacific of \$5 million for the years ending December 31, 2024, 2023 and 2022, respectively. Sierra Pacific provided services to Nevada Power of \$19 million, \$19 million, and \$16 million for the years ended December 31, 2024, 2023 and 2022, respectively. Nevada Power provided services to Sierra Pacific of \$31 million, \$28 million, and \$25 million for the years ended December 31, 2024, 2023 and 2022, respectively. Sierra Pacific provided services to NV Energy of \$3 million, \$1 million, and \$1 million for the years ended December 31, 2024, 2023 and 2022, respectively. As of December 31, 2024 and 2023, Sierra Pacific's Consolidated Balance Sheets included amounts due to NV Energy of \$54 million and \$24 million, respectively. There were no receivables due from NV Energy as of December 31, 2024 and 2023. As of December 31, 2024 and 2023, Sierra Pacific's Consolidated Balance Sheets included no payables due to Nevada Power. There were \$65 million and \$20 million receivables due from Nevada Power as of December 31, 2024 and 2023.

Sierra Pacific is party to a tax-sharing agreement and is part of the Berkshire Hathaway consolidated U.S. federal income tax return. Federal income taxes payable to BHE were \$3 million as of December 31, 2024 and federal income taxes receivable from BHE were \$4 million as of December 31, 2023. Sierra Pacific made cash payments for federal income tax to BHE of \$65 million and \$55 million for the years ended December 31, 2024 and 2023 and received cash refunds from BHE of \$1 million for federal income taxes for the year ended December 31, 2022.

Certain disbursements for accounts payable and payroll are made by NV Energy on behalf of Sierra Pacific and reimbursed automatically when settled by the bank. These amounts are recorded as accounts payable at the time of disbursement.

(18) Segment Information

Sierra Pacific's chief operating decision maker ("CODM") is its President and Chief Executive Officer. Net income for each reportable segment is considered by the CODM in allocating resources and capital. The CODM generally considers actual results versus historical results, budgets or forecasts, and state regulatory ratemaking results as well as unique risks and opportunities, when making decisions about the allocation of resources and capital to each reportable segment.

Sierra Pacific has identified two reportable operating segments: regulated electric and regulated natural gas. The regulated electric segment derives most of its revenue from regulated retail sales of electricity to residential, commercial, and industrial customers and from wholesale sales. The regulated natural gas segment derives most of its revenue from regulated retail sales of natural gas to residential, commercial, and industrial customers and also obtains revenue by transporting natural gas owned by others through its distribution system. Pricing for regulated electric and regulated natural gas sales are established separately by the PUCN; therefore, management also reviews each segment separately to make decisions regarding allocation of resources and in evaluating performance.

The following tables provide information on a reportable segment basis (in millions):

		2024	
	Regulated Electric	Regulated Natural Gas	Total
Operating revenue	\$ 1,080	\$ 182	\$ 1,262
Cost of sales	561	121	682
Operations and maintenance	213	32	245
Depreciation and amortization	162	19	181
Interest expense	79	7	86
Interest and dividend income	12	—	12
Income tax expense (benefit)	12	(2)	10
Other segment items ⁽¹⁾	17	(2)	15
Net income	<u>\$ 82</u>	<u>\$ 3</u>	<u>\$ 85</u>
Capital expenditures	<u>\$ 643</u>	<u>\$ 31</u>	<u>\$ 674</u>

	2023		
	Regulated Electric	Regulated Natural Gas	Total
Operating revenue	\$ 1,194	\$ 237	\$ 1,431
Cost of sales	689	176	865
Operations and maintenance	182	22	204
Depreciation and amortization	168	17	185
Interest expense	62	4	66
Interest and dividend income	20	2	22
Income tax expense (benefit)	14	2	16
Other segment items ⁽¹⁾	(1)	1	—
Net Income	<u>\$ 98</u>	<u>\$ 19</u>	<u>\$ 117</u>

Capital expenditures	<u>\$ 350</u>	<u>\$ 38</u>	<u>\$ 388</u>

	2022		
	Regulated Electric	Regulated Natural Gas	Total
Operating revenue	\$ 1,025	\$ 168	\$ 1,193
Cost of sales	555	111	666
Operations and maintenance	170	19	189
Depreciation and amortization	132	17	149
Interest expense	55	3	58
Interest and dividend income	16	2	18
Income tax expense (benefit)	15	4	19
Other segment items ⁽¹⁾	(12)	—	(12)
Net Income	<u>\$ 102</u>	<u>\$ 16</u>	<u>\$ 118</u>

Capital expenditures	<u>\$ 304</u>	<u>\$ 47</u>	<u>\$ 351</u>

	As of December 31,		
	2024	2023	2022
Assets			
Regulated electric	\$ 4,767	\$ 4,251	\$ 4,224
Regulated natural gas	518	454	441
Regulated common assets ⁽²⁾	42	67	67
Total assets	<u>\$ 5,327</u>	<u>\$ 4,772</u>	<u>\$ 4,732</u>

(1) Consists principally of property and other taxes, allowance for borrowed and equity funds and other income (expense).

(2) Consists principally of cash and cash equivalents not included in either the regulated electric or regulated natural gas segments

Eastern Energy Gas Holdings, LLC and its subsidiaries
Consolidated Financial Section

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

The following is management's discussion and analysis of certain significant factors that have affected the consolidated financial condition and results of operations of Eastern Energy Gas during the periods included herein. This discussion should be read in conjunction with Eastern Energy Gas' historical Consolidated Financial Statements and Notes to Consolidated Financial Statements in Item 8 of this Form 10-K. Eastern Energy Gas' actual results in the future could differ significantly from the historical results.

Results of Operations

Overview

Net income attributable to Eastern Energy Gas for the year ended December 31, 2024 was \$591 million, an increase of \$117 million, or 25%, compared to 2023, primarily due to higher earnings from Cove Point of \$151 million, largely due to the acquisition of an additional 50% limited partner interest in Cove Point, partially offset by one-time favorable income tax adjustments recorded in 2023 as a result of the acquisition of an additional 50% limited partner interest in Cove Point.

Net income attributable to Eastern Energy Gas for the year ended December 31, 2023 was \$474 million, an increase of \$48 million, or 11%, compared to 2022, primarily due to the acquisition of an additional 50% limited partner interest in Cove Point, lower income tax expense primarily due to favorable state tax adjustments, higher earnings from Iroquois due to favorable negotiated rate agreements and hedges and interest income from higher outstanding loans and higher interest rates under BHE GT&S' intercompany revolving credit agreement, partially offset by a benefit in 2022 from the settlement of regulated tax matters in the Iroquois rate case, lower margin from EGTS' regulated gas transmission and storage operations of \$20 million, an increase in salaries, wages and benefits and higher technology and related charges.

Year Ended December 31, 2024 Compared to Year Ended December 31, 2023

Operating revenue decreased \$48 million, or 2%, for 2024 compared to 2023, primarily due to a decrease in Cove Point's storage-related revenues of \$22 million, a decrease in EGTS' variable revenue related to park and loan activity of \$18 million, a decrease in regulated gas sales for operational and system balancing purposes due to decreased prices and volumes of \$15 million, a decrease in Cove Point LNG variable revenue of \$7 million, a decrease in Cove Point's regulated gas transmission service revenues due to decreased prices and volumes of \$5 million and a decrease in services provided to affiliates of \$5 million, partially offset by an increase in EGTS' regulated gas transmission and storage services revenues primarily due to higher volumes of \$17 million and an increase in CGT's regulated gas transmission service revenues of \$12 million primarily due to the settlement of its general rate case.

Cost of (excess) gas decreased \$31 million, or 82%, for 2024 compared to 2023, primarily due to the unfavorable revaluation of volumes retained in 2023.

Operations and maintenance decreased \$17 million, or 3%, for 2024 compared to 2023, primarily due to lower technology and related charges of \$19 million, lower outside services of \$9 million due to the termination of Dominion Energy Inc.'s transition services agreement and a decrease in services provided to affiliates of \$5 million, partially offset by a gain in 2023 from an agreement to convey development rights underneath one of its natural gas storage fields of \$8 million and an increase in salary and benefit expenses of \$4 million.

Depreciation and amortization increased \$14 million, or 4%, for 2024 compared to 2023, primarily due to higher plant placed in-service of \$9 million and the settlement of depreciation rates in CGT's general rate case of \$5 million.

Interest expense decreased \$5 million, or 3%, for 2024 compared to 2023, primarily due to the repayments of \$650 million of long-term debt during 2023 of \$17 million, partially offset by timing impacts and higher interest rates on \$1.0 billion of long-term debt re-financed during 2024 of \$8 million and higher lending activity under BHE GT&S' intercompany revolving credit agreement of \$4 million.

Interest and dividend income decreased \$16 million, or 53%, for 2024 compared to 2023, primarily due to lower lending activity under BHE GT&S' intercompany revolving credit agreement.

Income tax expense increased \$90 million, or 82%, for 2024 compared to 2023 and the effective tax rate was 24% for 2024 and 13% for 2023. The effective tax rate increased primarily due to ownership of 75% of the limited partner interests in Cove Point for the full year 2024 and a one-time favorable adjustments of \$26 million recorded in 2023, both as a result of the acquisition of an additional 50% limited partner interest in Cove Point on September 1, 2023.

Net income attributable to noncontrolling interests decreased \$226 million, or 63%, for 2024 compared to 2023, primarily due to the acquisition of an additional 50% limited partner interest in Cove Point.

Year Ended December 31, 2023 Compared to Year Ended December 31, 2022

Operating revenue increased \$53 million, or 3%, for 2023 compared to 2022, primarily due to an increase in regulated gas transmission and storage services revenues primarily due to the settlement of EGTS' general rate case of \$49 million, increased LNG service as a result of decreased scheduled maintenance days of \$26 million, an increase in EGTS' variable revenue related to park and loan activity of \$17 million and an increase in regulated gas sales for operational and system balancing purposes primarily due to increased volumes of \$15 million, partially offset by a net decrease in regulated gas transmission and storage services revenues due to volumes primarily from the expiration of the Appalachian Gateway Project contracts in August 2022 of \$29 million and a decrease in Cove Point LNG variable revenue of \$26 million.

Cost of (excess) gas was an expense of \$38 million for 2023 compared to a credit of \$30 million for 2022. The change is primarily from a decrease from other operational and system balancing fuel activities prior to the effective date of the new fuel tracker due to the settlement of EGTS' general rate case of \$45 million and the unfavorable revaluation of the volumes retained prior to the effective date of the new fuel tracker due to lower natural gas prices of \$27 million.

Operations and maintenance increased \$60 million, or 11%, for 2023 compared to 2022, primarily due to an increase in salaries, wages and benefits of \$28 million, higher technology and related charges of \$11 million, an increase in operational materials and services of \$10 million and an increase in fuel used in operations primarily due to volumes of \$6 million, partially offset by a gain from an agreement to convey development rights underneath one of its natural gas storage fields of \$8 million.

Depreciation and amortization increased \$1 million for 2023 compared to 2022, primarily due to higher plant placed in-service of \$9 million, partially offset by the settlement of depreciation rates in EGTS' general rate case of \$8 million.

Property and other taxes decreased \$5 million, or 4%, for 2023 compared to 2022, primarily due to lower than estimated 2022 tax assessments.

Interest and dividend income increased \$23 million for 2023 compared to 2022, primarily due to interest income from higher outstanding loans and higher interest rates under BHE GT&S' intercompany revolving credit agreement of \$13 million and income from money market mutual fund investments of \$10 million.

Income tax expense decreased \$57 million, or 34%, for 2023 compared to 2022 and the effective tax rate was 13% for 2023 and 18% for 2022. The effective tax rate decreased primarily due to various changes in the state effective rate related to the acquisition of an additional 50% limited partner interest in Cove Point.

Equity income decreased \$29 million, or 28%, for 2023 compared to 2022, primarily due to a benefit in 2022 from the settlement of regulated tax matters in the Iroquois rate case of \$45 million, offset by higher earnings from Iroquois due to favorable negotiated rate agreements and hedges of \$16 million.

Net income attributable to noncontrolling interests decreased \$67 million, or 16%, for 2023 compared to 2022, primarily due to the acquisition of an additional 50% limited partner interest in Cove Point of \$63 million and lower net income attributable to Cove Point of \$4 million.

Liquidity and Capital Resources

As of December 31, 2024, Eastern Energy Gas' total net liquidity was as follows (in millions):

Cash and cash equivalents	\$	34
Intercompany revolving credit agreement ⁽¹⁾		400
Total net liquidity	\$	434
Intercompany revolving credit agreement:		
Maturity date		2026

- (1) Refer to Note 19 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for further discussion regarding Eastern Energy Gas' intercompany revolving credit agreement.

Operating Activities

Net cash flows from operating activities for the years ended December 31, 2024 and 2023 were \$1.3 billion and \$1.2 billion, respectively. The change was primarily due to the repayment of EGTS rate refunds to customers in 2023, the settlement of contract liabilities in 2023 and other changes in working capital, partially offset by unfavorable operating results.

Net cash flows from operating activities for the years ended December 31, 2023 and 2022 were \$1.2 billion and \$1.3 billion, respectively. The change was primarily due to the timing of income tax payments and the repayment of EGTS rate refunds to customers, partially offset by the timing of payments for operating costs and other changes in working capital.

Investing Activities

Net cash flows from investing activities for the years ended December 31, 2024 and 2023 were \$(372) million and \$177 million, respectively. The change was primarily due to a decrease in repayments of notes by its parent under an intercompany revolving credit agreement of \$429 million, an increase in notes issued to its parent under an intercompany revolving credit agreement of \$107 million, an increase in capital expenditures of \$11 million and proceeds from the assignment of shale development rights in 2023 of \$8 million.

Net cash flows from investing activities for the years ended December 31, 2023 and 2022 were \$177 million and \$(778) million, respectively. The change was primarily due to an increase in repayments of notes by its parent under an intercompany revolving credit agreement of \$695 million, a decrease in notes issued to its parent under an intercompany revolving credit agreement of \$366 million, a decrease in capital expenditures of \$22 million and proceeds from the assignment of shale development rights of \$8 million, partially offset by equity method distribution of \$150 million in 2022.

Financing Activities

Net cash flows from financing activities for the year ended December 31, 2024 were \$(925) million. Sources of cash totaled \$1.0 billion and consisted of proceeds from the issuance of long-term debt. Uses of cash totaled \$2.0 billion and consisted of repayments of long-term debt of \$1.1 billion, net repayment of notes payable to affiliates of \$400 million, distributions to its indirect parent, BHE, of \$361 million and distributions to noncontrolling interests from Cove Point of \$155 million.

Net cash flows from financing activities for the year ended December 31, 2023 were \$(1.4) billion. Sources of cash totaled \$3.3 billion and consisted of proceeds from equity contributions to fund the purchase of Cove Point noncontrolling interest of \$2.9 billion and net issuance of notes payable to affiliates of \$400 million. Uses of cash totaled \$4.7 billion and consisted of \$3.3 billion for the purchase of Cove Point noncontrolling interest, repayment of long-term debt of \$650 million, distributions to noncontrolling interests from Cove Point of \$388 million and distributions to its indirect parent, BHE, of \$332 million.

Net cash flows from financing activities for the year ended December 31, 2022 were \$(515) million and consisted of distributions to noncontrolling interests from Cove Point.

Short-term Debt

As of December 31, 2023, Eastern Energy Gas had \$400 million of an outstanding note payable to an affiliate at a weighted average interest rate of 5.84%. There were no amounts outstanding under the credit agreement as of December 31, 2024. For further discussion, refer to Note 19 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Long-term Debt

In January 2025, Eastern Energy Gas issued \$700 million of 5.80% Senior Notes due 2035 and \$500 million of 6.20% Senior Notes due 2055. Eastern Energy Gas intends to use the net proceeds from the sale of the notes to rebalance its capitalization structure by returning a portion of the equity capital received from its indirect parent, BHE.

Eastern Energy Gas currently has an effective shelf registration statement with the SEC to issue an additional \$400 million of long-term debt securities through January 11, 2027.

Future Uses of Cash

Capital Expenditures

Capital expenditure needs are reviewed regularly by management and may change significantly as a result of these reviews, which may consider, among other factors, new growth projects and the timing of growth projects; changes in environmental and other rules and regulations; impacts to customers' rates; outcomes of regulatory proceedings; changes in income tax laws; general business conditions; system reliability standards; the cost and efficiency of construction labor, equipment and materials; commodity prices; and the cost and availability of capital.

Eastern Energy Gas' historical and forecasted capital expenditures, each of which exclude amounts for non-cash equity AFUDC and other non-cash items, for the years ending December 31 are as follows (in millions):

	Historical			Forecast		
	2022	2023	2024	2025	2026	2027
Natural gas transmission and storage	\$ 43	\$ 23	\$ 64	\$ 80	\$ 92	\$ 299
Other	344	342	312	293	346	242
Total	<u>\$ 387</u>	<u>\$ 365</u>	<u>\$ 376</u>	<u>\$ 373</u>	<u>\$ 438</u>	<u>\$ 541</u>

Eastern Energy Gas' natural gas transmission and storage capital expenditures primarily include growth capital expenditures related to planned regulated projects. Eastern Energy Gas' other capital expenditures consist primarily of nonregulated and routine capital expenditures for natural gas transmission, storage and LNG terminalling infrastructure needed to serve existing and expected demand.

Off-Balance Sheet Arrangements

Eastern Energy Gas has certain investments that are accounted for under the equity method in accordance with GAAP. Accordingly, an amount is recorded on Eastern Energy Gas' Consolidated Balance Sheets as an equity investment and is increased or decreased for Eastern Energy Gas' pro-rata share of earnings or losses, respectively, less any dividends from such investments.

As of December 31, 2024, Eastern Energy Gas' investments that are accounted for under the equity method had short- and long-term debt of \$299 million and an unused revolving credit facility of \$10 million. As of December 31, 2024, Eastern Energy Gas' pro-rata share of such short- and long-term debt was \$150 million and unused revolving credit facility was \$5 million. The entire amount of Eastern Energy Gas' pro-rata share of the outstanding short- and long-term debt and unused revolving credit facility is non-recourse to Eastern Energy Gas. Although Eastern Energy Gas is generally not required to support debt service obligations of its equity investees, default with respect to this non-recourse short- and long-term debt could result in a loss of invested equity.

Material Cash Requirements

The following table summarizes Eastern Energy Gas' material cash requirements as of December 31, 2024 (in millions):

	Payments Due by Periods				
	2025	2026-2027	2028-2029	2030 and thereafter	Total
Interest payments on long-term debt ⁽¹⁾	\$ 146	\$ 281	\$ 272	\$ 2,166	\$ 2,865
Natural gas supply and transmission ⁽¹⁾	46	94	94	47	281
Total cash requirements	<u>\$ 192</u>	<u>\$ 375</u>	<u>\$ 366</u>	<u>\$ 2,213</u>	<u>\$ 3,146</u>

(1) Not reflected on the Consolidated Balance Sheets.

In addition, Eastern Energy Gas also has cash requirements that may affect its consolidated financial condition that arise from long-term debt (refer to Note 8), construction and other development costs (refer to Liquidity and Capital Resources included within this Item 7), uncertain tax positions (refer to Note 9) and AROs (refer to Note 11). Refer, where applicable, to the respective referenced note in Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

Regulatory Matters

Eastern Energy Gas is subject to comprehensive regulation. Refer to the discussion contained in Item 1 of this Form 10-K for further information regarding Eastern Energy Gas' general regulatory framework and current regulatory matters.

Environmental Laws and Regulations

Eastern Energy Gas is subject to federal, state and local laws and regulations regarding air quality, climate change, emissions performance standards, water quality and other environmental matters that have the potential to impact its current and future operations. In addition to imposing continuing compliance obligations, these laws and regulations provide regulators with the authority to levy substantial penalties for noncompliance, including fines, injunctive relief and other sanctions. These laws and regulations are administered by various federal, state and local agencies. Eastern Energy Gas believes it is in material compliance with all applicable laws and regulations, although many are subject to interpretation that may ultimately be resolved by the courts. Environmental laws and regulations continue to evolve, and Eastern Energy Gas is unable to predict the impact of the changing laws and regulations on its operations and financial results.

Refer to "Environmental Laws and Regulations" in Item 1 of this Form 10-K for further discussion regarding environmental laws and regulations.

Collateral and Contingent Features

Debt of Eastern Energy Gas is rated by credit rating agencies. Assigned credit ratings are based on each rating agency's assessment of Eastern Energy Gas' ability to, in general, meet the obligations of its issued debt. The credit ratings are not a recommendation to buy, sell or hold securities, and there is no assurance that a particular credit rating will continue for any given period of time.

Eastern Energy Gas has no credit rating downgrade triggers that would accelerate the maturity dates of outstanding debt, and a change in ratings is not an event of default under the applicable debt instruments.

Inflation

Historically, overall inflation and changing prices in the economies where Eastern Energy Gas operates have not had a significant impact on Eastern Energy Gas' consolidated financial results. Eastern Energy Gas and its subsidiaries primarily operate under cost-of-service based rate-setting structures administered by the FERC. Under these rate-setting structures, Eastern Energy Gas is allowed to include prudent costs in its rates, including the impact of inflation. Eastern Energy Gas attempts to minimize the potential impact of inflation on its operations by employing prudent risk management and hedging strategies and by considering, among other areas, its impact on purchases of energy, operating expenses, materials and equipment costs, contract negotiations, future capital spending programs and long-term debt issuances. There can be no assurance that such actions will be successful.

New Accounting Pronouncements

For a discussion of new accounting pronouncements affecting Eastern Energy Gas, refer to Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Critical Accounting Estimates

Certain accounting measurements require management to make estimates and judgments concerning transactions that will be settled several years in the future. Amounts recognized on the Consolidated Financial Statements based on such estimates involve numerous assumptions subject to varying and potentially significant degrees of judgment and uncertainty and will likely change in the future as additional information becomes available. The following critical accounting estimates are impacted significantly by Eastern Energy Gas' methods, judgments and assumptions used in the preparation of the Consolidated Financial Statements and should be read in conjunction with Eastern Energy Gas' Summary of Significant Accounting Policies included in Eastern Energy Gas' Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Accounting for the Effects of Certain Types of Regulation

Eastern Energy Gas prepares its Consolidated Financial Statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, Eastern Energy Gas defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in regulated rates occur.

Eastern Energy Gas continually evaluates the applicability of the guidance for regulated operations and whether its regulatory assets and liabilities are probable of inclusion in future regulated rates by considering factors such as a change in the regulator's approach to setting rates from cost-based ratemaking to another form of regulation, other regulatory actions or the impact of competition that could limit Eastern Energy Gas' ability to recover its costs. Eastern Energy Gas believes its application of the guidance for regulated operations is appropriate and its existing regulatory assets and liabilities are probable of inclusion in future regulated rates. The evaluation reflects the current political and regulatory climate at the federal level. If it becomes no longer probable that the deferred costs or income will be included in future regulated rates, the related regulatory assets and liabilities will be recognized in net income, returned to customers or re-established as AOCI. Total regulatory assets were \$41 million and total regulatory liabilities were \$656 million as of December 31, 2024. Refer to Eastern Energy Gas' Note 6 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding Eastern Energy Gas' regulatory assets and liabilities.

Impairment of Goodwill and Long-Lived Assets

Eastern Energy Gas' Consolidated Balance Sheet as of December 31, 2024 includes goodwill of acquired businesses of \$1.3 billion. Eastern Energy Gas evaluates goodwill for impairment at least annually and completed its annual review as of October 31, 2024. Additionally, no indicators of impairment were identified as of December 31, 2024. Significant judgment is required in estimating the fair value of the reporting unit and performing goodwill impairment tests. Eastern Energy Gas uses a variety of methods to estimate a reporting unit's fair value, principally discounted projected future net cash flows. Key assumptions used include, but are not limited to, the use of estimated future cash flows; multiples of earnings; and an appropriate discount rate. Estimated future cash flows are impacted by, among other factors, growth rates, changes in regulations and rates, ability to renew contracts and estimates of future commodity prices. In estimating future cash flows, Eastern Energy Gas incorporates current market information, as well as historical factors.

Eastern Energy Gas evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or when the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value and any resulting impairment loss is reflected on the Consolidated Statements of Operations. As a majority of all property, plant and equipment is used in regulated businesses, the impacts of regulation are considered when evaluating the carrying value of regulated assets.

The estimate of cash flows arising from the future use of an asset, for the purposes of impairment analysis, requires the exercise of judgment. Circumstances that could significantly alter the calculation of fair value or the recoverable amount of an asset may include significant changes in the regulatory environment, the business climate, management's plans, legal factors, market price of the asset, the use of the asset, the physical condition of the asset, future market prices, competition and many other factors over the life of the asset. Any resulting impairment loss is highly dependent on the underlying assumptions and could significantly affect Eastern Energy Gas' results of operations.

Income Taxes

In determining Eastern Energy Gas' income taxes, management is required to interpret complex income tax laws and regulations, which includes consideration of regulatory implications imposed by the FERC. Eastern Energy Gas' income tax returns are subject to continuous examinations by federal, state and local income tax authorities that may give rise to different interpretations of these complex laws and regulations. Due to the nature of the examination process, it generally takes years before these examinations are completed and these matters are resolved. Eastern Energy Gas recognizes the tax benefit from an uncertain tax position only if it is more-likely-than-not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the Consolidated Financial Statements from such a position are measured based on the largest benefit that is more-likely-than-not to be realized upon ultimate settlement. Although the ultimate resolution of Eastern Energy Gas' federal, state and local income tax examinations is uncertain, Eastern Energy Gas believes it has made adequate provisions for these income tax positions. The aggregate amount of any additional income tax liabilities that may result from these examinations is not expected to have a material impact on Eastern Energy Gas' consolidated financial results. Refer to Eastern Energy Gas' Note 9 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding Eastern Energy Gas' income taxes.

It is probable that Eastern Energy Gas will pass income tax benefit and expense related to the federal tax rate change from 35% to 21%, certain property-related basis differences and other various differences on to their customers. As of December 31, 2024, these amounts were recognized as a net regulatory liability of \$416 million and will be included in regulated rates when the temporary differences reverse.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Eastern Energy Gas' Consolidated Balance Sheets include assets and liabilities with fair values that are subject to market risks. Eastern Energy Gas' significant market risks are primarily associated with interest rates, foreign currency and the extension of credit to counterparties with which Eastern Energy Gas transacts. The following discussion addresses the significant market risks associated with Eastern Energy Gas' business activities. Eastern Energy Gas has established guidelines for credit risk management. Refer to Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding Eastern Energy Gas' contracts accounted for as derivatives.

Interest Rate Risk

Eastern Energy Gas is exposed to interest rate risk on its outstanding variable-rate short- and long-term debt and future debt issuances. Eastern Energy Gas manages its interest rate risk by limiting its exposure to variable interest rates primarily through the issuance of fixed-rate long-term debt and by monitoring market changes in interest rates. As a result of the fixed interest rates, Eastern Energy Gas' fixed-rate long-term debt does not expose Eastern Energy Gas to the risk of loss due to changes in market interest rates. Additionally, because fixed-rate long-term debt is not carried at fair value on the Consolidated Balance Sheets, changes in fair value would impact earnings and cash flows only if Eastern Energy Gas were to reacquire all or a portion of these instruments prior to their maturity. The nature and amount of Eastern Energy Gas' short- and long-term debt can be expected to vary from period to period as a result of future business requirements, market conditions and other factors. Refer to Note 8 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional discussion of Eastern Energy Gas' long-term debt.

As of December 31, 2024 and 2023, Eastern Energy Gas had short-term variable-rate obligations totaling \$— million and \$400 million, respectively, that expose Eastern Energy Gas to the risk of increased interest expense in the event of increases in short-term interest rates. If variable interest rates were to increase by 10% from December 31 levels, it would not have a material effect on Eastern Energy Gas' annual interest expense. The carrying value of the variable-rate obligations approximates fair value as of December 31, 2024 and 2023.

Eastern Energy Gas holds foreign currency swaps with the purpose of hedging the foreign currency exchange risk associated with Euro denominated debt. As of December 31, 2024 and 2023, Eastern Energy Gas had €250 million in aggregate notional amounts of these foreign currency swaps outstanding. A hypothetical 10% decrease in market interest rates would not have resulted in a material decrease in fair value of Eastern Energy Gas' foreign currency swaps as of December 31, 2024 and 2023.

The impact of a change in interest rates on the Eastern Energy Gas' interest rate-based financial derivative instruments at a point in time is not necessarily representative of the results that will be realized when the contracts are ultimately settled. Net gains and/or losses from interest rate derivative instruments used for hedging purposes, to the extent realized, will generally be offset by recognition of the hedged transaction.

Credit Risk

Eastern Energy Gas is exposed to counterparty credit risk associated with natural gas transmission and storage service contracts with utilities, natural gas producers, power generators, industrials, energy marketing companies, financial institutions and other market participants. Credit risk may be concentrated to the extent Eastern Energy Gas' counterparties have similar economic, industry or other characteristics and due to direct and indirect relationships among the counterparties. Before entering into a transaction, Eastern Energy Gas analyzes the financial condition of each wholesale counterparty, establishes limits on the amount of unsecured credit to be extended to each counterparty and evaluates the appropriateness of unsecured credit limits on an ongoing basis. To further mitigate counterparty credit risk, Eastern Energy Gas obtains third-party guarantees, letters of credit, financial guarantee bonds and cash deposits. If required, Eastern Energy Gas exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

Eastern Energy Gas' gross credit exposure for each counterparty is calculated as outstanding receivables plus any unrealized on- or off-balance sheet exposure, taking into account contractual netting rights. Gross credit exposure is calculated prior to the application of collateral. As of December 31, 2024, Eastern Energy Gas' credit exposure totaled \$46 million. Of this amount, investment grade counterparties, including those internally rated, represented 100%, with three investment grade counterparties representing 71% of the credit exposure.

Item 8. Financial Statements and Supplementary Data

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Eastern Energy Gas Holdings, LLC

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Eastern Energy Gas Holdings, LLC and subsidiaries ("Eastern Energy Gas") as of December 31, 2024 and 2023, the related consolidated statements of operations, comprehensive income, changes in equity, and cash flows, for each of the three years in the period ended December 31, 2024, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of Eastern Energy Gas as of December 31, 2024 and 2023, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2024, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of Eastern Energy Gas' management. Our responsibility is to express an opinion on Eastern Energy Gas' financial statements 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 Eastern Energy Gas 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 financial statements are free of material misstatement, whether due to error or fraud. Eastern Energy Gas is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of Eastern Energy Gas' internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the 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 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 financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the executive committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the 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.

Regulatory Matters — Effects of Rate Regulation on the Financial Statements — Refer to Notes 2 and 6 to the Financial Statements

Critical Audit Matter Description

Eastern Energy Gas, through its subsidiaries, is subject to rate regulation by the Federal Energy Regulatory Commission (the "FERC"), which has jurisdiction with respect to the rates of interstate natural gas transmission companies in the respective service territories where Eastern Energy Gas operates. Management has determined its regulated operations meet the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the specialized rules to account for the effects of cost-based rate regulation. Accounting for the economic effects of rate regulation has a pervasive effect on the financial statements.

Revenue provided by the Eastern Energy Gas interstate natural gas transmission operations is based primarily on rates approved by the FERC. Eastern Energy Gas defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in regulated rates occur. Eastern Energy Gas continually evaluates the applicability of the guidance for regulated operations and whether its regulatory assets and liabilities are probable of inclusion in future rates by considering factors such as a change in the regulator's approach to setting rates from cost-based ratemaking to another form of regulation, other regulatory actions or the impact of competition that could limit Eastern Energy Gas' ability to recover its costs. The evaluation reflects the current political and regulatory climate. If it becomes no longer probable that the deferred costs or income will be included in future regulated rates, the regulatory assets and liabilities will be recognized in net income, returned to customers, or re-established as accumulated other comprehensive income (loss).

We identified the effects of rate regulation on the financial statements as a critical audit matter due to the significant judgments made by management to support its assertions about affected account balances and disclosures and the high degree of subjectivity involved in assessing the impact of regulatory orders on the financial statements. Management judgments include assessing the likelihood of (1) recovery in future rates of incurred costs, (2) a disallowance of part of the cost of recently completed plant or plant under construction, and (3) a refund to customers. Given that management's accounting judgments are based on assumptions about the outcome of decisions by the FERC, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate setting process due to its inherent complexities.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the uncertainty of decisions by the FERC included the following, among others:

- We evaluated the Eastern Energy Gas disclosures related to the effects of rate regulation by testing recorded balances and evaluating regulatory developments.
- We read relevant regulatory orders issued by the FERC, regulatory statutes, filings made by Eastern Energy Gas and intervenors, and other external information. We evaluated relevant external information and compared it to certain recorded regulatory asset and liability balances for completeness.
- For certain regulatory matters, we inspected Eastern Energy Gas' filings with the FERC, and the filings with the FERC by intervenors to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedents of the FERC's treatment of similar costs under similar circumstances.
- We inquired of management about property, plant, and equipment that may be abandoned. We inquired of management to identify projects that are designed to replace assets that may be retired prior to the end of the useful life. We inspected minutes of the board of directors and regulatory orders and other filings with the FERC to identify any evidence that may contradict management's assertion regarding probability of an abandonment.

/s/ Deloitte & Touche LLP

Richmond, Virginia
February 21, 2025

We have served as Eastern Energy Gas' auditor since 2012.

EASTERN ENERGY GAS HOLDINGS, LLC AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Amounts in millions)

	As of December 31,	
	2024	2023
ASSETS		
Current assets:		
Cash and cash equivalents	\$ 34	\$ 62
Restricted cash and cash equivalents	27	31
Trade receivables, net	189	195
Receivables from affiliates	33	25
Inventories	143	142
Income taxes receivable	—	80
Prepayments and other deferred charges	85	76
Natural gas imbalances	71	39
Other current assets	25	20
Total current assets	607	670
Property, plant and equipment, net	10,338	10,343
Goodwill	1,286	1,286
Investments	261	281
Other assets	85	120
Total assets	\$ 12,577	\$ 12,700

The accompanying notes are an integral part of these consolidated financial statements.

EASTERN ENERGY GAS HOLDINGS, LLC AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (continued)
(Amounts in millions)

	As of December 31,	
	2024	2023
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	\$ 86	\$ 89
Accounts payable to affiliates	33	45
Accrued property, income and other taxes	291	93
Notes payable to affiliates	—	400
Regulatory liabilities	29	33
Current portion of long-term debt	—	1,050
Other current liabilities	108	108
Total current liabilities	547	1,818
Long-term debt	3,231	2,204
Regulatory liabilities	627	623
Deferred income taxes	498	383
Other long-term liabilities	139	144
Total liabilities	5,042	5,172
Commitments and contingencies (Note 14)		
Equity:		
Members' equity:		
Membership interests	6,300	6,273
Accumulated other comprehensive loss, net	(35)	(40)
Total members' equity	6,265	6,233
Noncontrolling interests	1,270	1,295
Total equity	7,535	7,528
Total liabilities and equity	\$ 12,577	\$ 12,700

The accompanying notes are an integral part of these consolidated financial statements.

EASTERN ENERGY GAS HOLDINGS, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2024	2023	2022
Operating revenue	\$ 2,011	\$ 2,059	\$ 2,006
Operating expenses:			
Cost of (excess) gas	7	38	(30)
Operations and maintenance	573	590	530
Depreciation and amortization	336	322	321
Property and other taxes	133	134	139
Total operating expenses	1,049	1,084	960
Operating income	962	975	1,046
Other income (expense):			
Interest expense	(141)	(146)	(147)
Allowance for borrowed funds	4	2	2
Allowance for equity funds	9	8	6
Interest and dividend income	14	30	7
Other, net	1	(3)	(1)
Total other income (expense)	(113)	(109)	(133)
Income before income tax expense (benefit) and equity income (loss)	849	866	913
Income tax expense (benefit)	200	110	167
Equity income (loss)	72	74	103
Net income	721	830	849
Net income attributable to noncontrolling interests	130	356	423
Net income attributable to Eastern Energy Gas	<u>\$ 591</u>	<u>\$ 474</u>	<u>\$ 426</u>

The accompanying notes are an integral part of these consolidated financial statements.

EASTERN ENERGY GAS HOLDINGS, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Amounts in millions)

	Years Ended December 31,		
	2024	2023	2022
Net income	\$ 721	\$ 830	\$ 849
Other comprehensive income, net of tax:			
Unrecognized amounts on retirement benefits, net of tax of \$—, \$(1) and \$—	1	(2)	5
Unrealized gains (losses) on cash flow hedges, net of tax of \$1, \$3 and \$—	4	5	(1)
Total other comprehensive income, net of tax	5	3	4
Comprehensive income	726	833	853
Comprehensive income attributable to noncontrolling interests	130	356	426
Comprehensive income attributable to Eastern Energy Gas	<u>\$ 596</u>	<u>\$ 477</u>	<u>\$ 427</u>

The accompanying notes are an integral part of these consolidated financial statements.

EASTERN ENERGY GAS HOLDINGS, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(Amounts in millions)

	Membership Interests	Accumulated Other Comprehensive Loss, Net	Noncontrolling Interests	Total Equity
Balance, December 31, 2021	\$ 3,501	\$ (43)	\$ 4,036	\$ 7,494
Net income	426	—	423	849
Other comprehensive income	—	1	3	4
Distributions	(42)	—	(515)	(557)
Contributions	98	—	—	98
Balance, December 31, 2022	3,983	(42)	3,947	7,888
Net income	474	—	356	830
Other comprehensive income	—	3	—	3
Distributions	(556)	—	(388)	(944)
Contributions	2,931	—	—	2,931
Purchase of Cove Point noncontrolling interest (Note 3)	(559)	(1)	(2,620)	(3,180)
Balance, December 31, 2023	6,273	(40)	1,295	7,528
Net income	591	—	130	721
Other comprehensive income	—	5	—	5
Distributions	(683)	—	(155)	(838)
Contributions	119	—	—	119
Balance, December 31, 2024	<u>\$ 6,300</u>	<u>\$ (35)</u>	<u>\$ 1,270</u>	<u>\$ 7,535</u>

The accompanying notes are an integral part of these consolidated financial statements.

EASTERN ENERGY GAS HOLDINGS, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Amounts in millions)

	Years Ended December 31,		
	2024	2023	2022
Cash flows from operating activities:			
Net income	\$ 721	\$ 830	\$ 849
Adjustments to reconcile net income to net cash flows from operating activities:			
Losses (gains) on other items, net	5	(3)	5
Depreciation and amortization	336	322	321
Allowance for equity funds	(9)	(8)	(6)
Equity (income) loss, net of distributions	20	(1)	(58)
Changes in regulatory assets and liabilities	1	(91)	56
Deferred income taxes	126	353	126
Other, net	3	(5)	8
Changes in other operating assets and liabilities:			
Trade receivables and other assets	29	(9)	(34)
Receivables from affiliates	(8)	3	28
Gas balancing activities	8	22	(29)
Derivative collateral, net	—	1	(1)
Accrued property, income and other taxes	35	(232)	27
Accounts payable to affiliates	(12)	35	(42)
Accounts payable and other liabilities	10	(19)	99
Net cash flows from operating activities	<u>1,265</u>	<u>1,198</u>	<u>1,349</u>
Cash flows from investing activities:			
Capital expenditures	(376)	(365)	(387)
Proceeds from assignment of shale development rights	—	8	—
Notes to affiliates	(305)	(198)	(564)
Repayment of notes by affiliates	305	734	39
Equity method investments	—	—	150
Other, net	4	(2)	(16)
Net cash flows from investing activities	<u>(372)</u>	<u>177</u>	<u>(778)</u>
Cash flows from financing activities:			
Proceeds from long-term debt	1,041	—	—
Repayments of long-term debt	(1,050)	(650)	—
(Repayment) issuance of notes payable to affiliates, net	(400)	400	—
Proceeds from equity contributions	—	2,893	—
Purchase of Cove Point noncontrolling interest	—	(3,300)	—
Distributions to noncontrolling interests	(155)	(388)	(515)
Distributions to parent	(361)	(332)	—
Net cash flows from financing activities	<u>(925)</u>	<u>(1,377)</u>	<u>(515)</u>
Net change in cash and cash equivalents and restricted cash and cash equivalents	(32)	(2)	56
Cash and cash equivalents and restricted cash and cash equivalents at beginning of period	93	95	39
Cash and cash equivalents and restricted cash and cash equivalents at end of period	<u>\$ 61</u>	<u>\$ 93</u>	<u>\$ 95</u>

The accompanying notes are an integral part of these consolidated financial statements.

EASTERN ENERGY GAS HOLDINGS, LLC AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Organization and Operations

Eastern Energy Gas Holdings, LLC is a holding company, and together with its subsidiaries ("Eastern Energy Gas") conducts business activities consisting of Federal Energy Regulatory Commission ("FERC")-regulated interstate natural gas transmission systems and underground storage operations in the eastern region of the U.S. and operates Cove Point LNG, LP ("Cove Point"), a liquefied natural gas ("LNG") export, import and storage facility. Eastern Energy Gas holds 100% of the general partner interest and 75% of the limited partner interests of Cove Point. In addition, Eastern Energy Gas holds a 50% noncontrolling interest in Iroquois Gas Transmission System, L.P. ("Iroquois"), a 414-mile FERC-regulated interstate natural gas transmission system. Eastern Energy Gas is an indirect wholly owned subsidiary of Berkshire Hathaway Energy Company ("BHE"). BHE is a holding company based in Des Moines, Iowa that has investments in subsidiaries principally engaged in energy businesses. BHE is a wholly owned subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway").

(2) Summary of Significant Accounting Policies

Basis of Consolidation and Presentation

The Consolidated Financial Statements include the accounts of Eastern Energy Gas and its subsidiaries in which it holds a controlling financial interest as of the financial statement date. Eastern Energy Gas consolidates variable interest entities ("VIE") in which it possesses both (i) the power to direct the activities that most significantly impact the entity's economic performance and (ii) the obligation to absorb losses or receive benefits from the entity that could potentially be significant to the VIE. Intercompany accounts and transactions have been eliminated.

Use of Estimates in Preparation of Financial Statements

The preparation of the Consolidated Financial Statements in conformity with accounting principles generally accepted in the United States of America ("GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the period. These estimates include, but are not limited to, the effects of regulation; impairment of goodwill; recovery of long-lived assets; certain assumptions made in accounting for pension and other postretirement benefits; asset retirement obligations ("AROs"); income taxes; unbilled revenue; valuation of certain financial assets and liabilities, including derivative contracts; and accounting for contingencies. Actual results may differ from the estimates used in preparing the Consolidated Financial Statements.

Accounting for the Effects of Certain Types of Regulation

Eastern Energy Gas prepares its Consolidated Financial Statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, Eastern Energy Gas defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in regulated rates occur.

If it becomes no longer probable that the deferred costs or income will be included in future regulated rates, the related regulatory assets and liabilities will be recognized in net income, returned to customers or re-established as accumulated other comprehensive income (loss) ("AOCI").

Fair Value Measurements

As defined under GAAP, fair value is the price that would be received to sell an asset or paid to transfer a liability between market participants in the principal market or in the most advantageous market when no principal market exists. Adjustments to transaction prices or quoted market prices may be required in illiquid or disorderly markets in order to estimate fair value. Alternative valuation techniques may be appropriate under the circumstances to determine the value that would be received to sell an asset or paid to transfer a liability in an orderly transaction. Market participants are assumed to be independent, knowledgeable, able and willing to transact an exchange and not under duress. Nonperformance or credit risk is considered when determining fair value. Considerable judgment may be required in interpreting market data used to develop the estimates of fair value. Accordingly, estimates of fair value presented herein are not necessarily indicative of the amounts that could be realized in a current or future market exchange.

Cash and Cash Equivalents and Restricted Cash and Cash Equivalents

Cash equivalents consist of funds invested in money market mutual funds, U.S. Treasury Bills and other investments with a maturity of three months or less when purchased. Cash and cash equivalents exclude amounts where availability is restricted by legal requirements, loan agreements or other contractual provisions. Restricted cash and cash equivalents consist of customer deposits as allowed under the FERC gas tariffs. A reconciliation of cash and cash equivalents and restricted cash and cash equivalents as of December 31, 2024 and 2023, as presented on the Consolidated Statements of Cash Flows is outlined below and disaggregated by the line items in which they appear on the Consolidated Balance Sheets (in millions):

	As of December 31,	
	2024	2023
Cash and cash equivalents	\$ 34	\$ 62
Restricted cash and cash equivalents	27	31
Total cash and cash equivalents and restricted cash and cash equivalents	<u>\$ 61</u>	<u>\$ 93</u>

Investments

Trading securities are carried at fair value with realized and unrealized gains and losses recognized in earnings.

Equity Method Investments

Eastern Energy Gas utilizes the equity method of accounting with respect to investments when it possesses the ability to exercise significant influence, but not control, over the operating and financial policies of the investee. The ability to exercise significant influence is presumed when the investor possesses more than 20% of the voting interests of the investee. This presumption may be overcome based on specific facts and circumstances that demonstrate that the ability to exercise significant influence is restricted. In applying the equity method, Eastern Energy Gas records the investment at cost and subsequently increases or decreases the carrying value of the investment by Eastern Energy Gas' share of the net earnings or losses and other comprehensive income ("OCI") of the investee. Eastern Energy Gas records dividends or other equity distributions as reductions in the carrying value of the investment.

Allowance for Credit Losses

Trade receivables are primarily short-term in nature with stated collection terms of less than one year from the date of origination and are stated at the outstanding principal amount, net of an estimated allowance for credit losses. The allowance for credit losses is based on Eastern Energy Gas' assessment of the collectability of amounts owed to Eastern Energy Gas by its customers. This assessment requires judgment regarding the ability of customers to pay or the outcome of any pending disputes. In measuring the allowance for credit losses for trade receivables, Eastern Energy Gas primarily utilizes credit loss history. However, Eastern Energy Gas may adjust the allowance for credit losses to reflect current conditions and reasonable and supportable forecasts that deviate from historical experience. The changes in the balance of the allowance for credit losses, which is included in trade receivables, net on the Consolidated Balance Sheets, is summarized as follows for the years ended December 31, (in millions):

	2024	2023	2022
Beginning balance	\$ 3	\$ 3	\$ 6
Write-offs, net	—	—	(3)
Ending balance	<u>\$ 3</u>	<u>\$ 3</u>	<u>\$ 3</u>

Derivatives

Eastern Energy Gas employs a number of different derivative contracts, which may include forwards, futures, options, swaps and other agreements, to manage its commodity price, interest rate, and foreign currency exchange rate risk. Derivative contracts are recorded on the Consolidated Balance Sheets as either assets or liabilities and are stated at estimated fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by GAAP. Derivative balances reflect offsetting permitted under master netting agreements with counterparties and cash collateral paid or received under such agreements. Cash collateral received from or paid to counterparties to secure derivative contract assets or liabilities in excess of amounts offset is included in other current assets or other current liabilities on the Consolidated Balance Sheets.

Commodity derivatives used in normal business operations that are settled by physical delivery, among other criteria, are eligible for and may be designated as normal purchases or normal sales. Normal purchases or normal sales contracts are not marked-to-market and settled amounts are recognized as operating revenue or cost of gas on the Consolidated Statements of Operations.

For Eastern Energy Gas' derivatives not designated as hedging contracts, unrealized gains and losses are recognized on the Consolidated Statements of Operations as operating revenue for derivatives related to natural gas sales contracts.

For Eastern Energy Gas' derivatives designated as hedging contracts, Eastern Energy Gas formally assesses, at inception and thereafter, whether the hedging contract is highly effective in offsetting changes in the hedged item. Eastern Energy Gas formally documents hedging activity by transaction type and risk management strategy. For derivative instruments that are accounted for as cash flow hedges or fair value hedges, the cash flows from the derivatives and from the related hedged items are classified in operating cash flows.

Changes in the estimated fair value of a derivative contract designated and qualified as a cash flow hedge, to the extent effective, are included on the Consolidated Statements of Changes in Equity as AOCI, net of tax, until the contract settles and the hedged item is recognized in earnings. Eastern Energy Gas discontinues hedge accounting prospectively when it has determined that a derivative contract no longer qualifies as an effective hedge, or when it is no longer probable that the hedged forecasted transaction will occur. When hedge accounting is discontinued because the derivative contract no longer qualifies as an effective hedge, future changes in the estimated fair value of the derivative contract are charged to earnings. Gains and losses related to discontinued hedges that were previously recorded in AOCI will remain in AOCI until the contract settles and the hedged item is recognized in earnings, unless it becomes probable that the hedged forecasted transaction will not occur at which time associated deferred amounts in AOCI are immediately recognized in earnings.

Inventories

Inventories consist mainly of materials and supplies and are determined using the average cost method.

Natural Gas Imbalances

Natural gas imbalances occur when the physical amount of natural gas delivered from, or received by, a pipeline system or storage facility differs from the contractual amount of natural gas delivered or received. Eastern Energy Gas values these imbalances due to, or from, shippers and operators at an appropriate index price at period end, subject to the terms of its tariff for regulated entities. Imbalances are primarily settled in-kind. Imbalances due to Eastern Energy Gas from other parties are reported in natural gas imbalances and imbalances that Eastern Energy Gas owes to other parties are reported in other current liabilities on the Consolidated Balance Sheets.

Property, Plant and Equipment, Net

General

Additions to property, plant and equipment are recorded at cost. Eastern Energy Gas capitalizes all construction-related materials, direct labor and contract services, as well as indirect construction costs. Indirect construction costs include capitalized interest, including debt allowance for funds used during construction ("AFUDC"), and equity AFUDC, as applicable. The cost of additions and betterments are capitalized, while costs incurred that do not improve or extend the useful lives of the related assets are generally expensed.

Depreciation and amortization are generally computed by applying the composite or straight-line method based on estimated useful lives. Depreciation studies are completed by Eastern Energy Gas for its regulated property, plant and equipment to determine the appropriate group lives, net salvage and group depreciation rates. These studies are reviewed and rates are ultimately approved by the FERC. Net salvage includes the estimated future residual values of the assets and any estimated removal costs recovered through approved depreciation rates. Estimated removal costs are recorded as either a cost of removal regulatory liability or an ARO liability on the Consolidated Balance Sheets, depending on whether the obligation meets the requirements of an ARO. As actual removal costs are incurred, the associated liability is reduced.

Generally when Eastern Energy Gas retires or sells a component of regulated property, plant and equipment, it charges the original cost, net of any proceeds from the disposition, to accumulated depreciation. Any gain or loss on disposals of all other assets is recorded through earnings.

Debt and equity AFUDC, which represent the estimated costs of debt and equity funds necessary to finance the construction of regulated facilities, is capitalized by Eastern Energy Gas as a component of property, plant and equipment, with offsetting credits to the Consolidated Statements of Operations. AFUDC is computed based on guidelines set forth by the FERC. After construction is completed, Eastern Energy Gas is permitted to earn a return on these costs as a component of the related assets, as well as recover these costs through depreciation expense over the useful lives of the related assets.

Asset Retirement Obligations

Eastern Energy Gas recognizes AROs when it has a legal obligation to perform decommissioning, reclamation or removal activities upon retirement of an asset. Eastern Energy Gas' AROs are primarily related to the obligations associated with its interstate natural gas transmission and storage well assets. The fair value of an ARO liability is recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made, and is added to the carrying amount of the associated asset, which is then depreciated over the remaining useful life of the asset. Subsequent to the initial recognition, the ARO liability is adjusted for any revisions to the original estimate of undiscounted cash flows (with corresponding adjustments to property, plant and equipment, net) and for accretion of the ARO liability due to the passage of time. For Eastern Energy Gas, the difference between the ARO liability, the corresponding ARO asset included in property, plant and equipment, net and amounts recovered in rates to satisfy such liabilities is recorded as a regulatory asset or liability.

Impairment

Eastern Energy Gas evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or when the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value and any resulting impairment loss is reflected on the Consolidated Statements of Operations. As a majority of all property, plant and equipment is used in regulated businesses, the impacts of regulation are considered when evaluating the carrying value of regulated assets.

Goodwill

Goodwill represents the excess of the purchase price over the fair value of identifiable net assets acquired in business combinations. Eastern Energy Gas evaluates goodwill for impairment at least annually and completed its annual review as of October 31, 2024. When evaluating goodwill for impairment, Eastern Energy Gas estimates the fair value of its reporting unit. If the carrying amount of a reporting unit, including goodwill, exceeds the estimated fair value, then the excess is charged to earnings as an impairment loss. Significant judgment is required in estimating the fair value of the reporting unit and performing goodwill impairment tests. The determination of fair value incorporates significant unobservable inputs. During 2024, 2023 and 2022, Eastern Energy Gas did not record any goodwill impairments.

Eastern Energy Gas records goodwill adjustments for changes to the purchase price allocation prior to the end of the measurement period, which is not to exceed one year from the acquisition date.

Revenue Recognition

Eastern Energy Gas uses a single five-step model to identify and recognize revenue from contracts with customers ("Customer Revenue") upon transfer of control of promised goods or services in an amount that reflects the consideration to which Eastern Energy Gas expects to be entitled in exchange for those goods or services. Eastern Energy Gas records sales and excise taxes collected directly from customers and remitted directly to the taxing authorities on a net basis on the Consolidated Statements of Operations.

A majority of Eastern Energy Gas' Customer Revenue is derived from tariff-based sales arrangements approved by the FERC. These tariff-based revenues are mainly comprised of natural gas transmission and storage services and have performance obligations which are satisfied over time as services are provided. Eastern Energy Gas' revenue that is nonregulated primarily relates to LNG terminalling services and have performance obligations which are satisfied over time as services are provided.

Revenue recognized is equal to the value to the customer of Eastern Energy Gas' performance to date and includes billed and unbilled amounts. As of December 31, 2024 and 2023, trade receivables, net on the Consolidated Balance Sheets relate substantially to Customer Revenue, including unbilled revenue of \$12 million and \$26 million, respectively. Payments for amounts billed are generally due from the customer within 30 days of billing. Rates charged for energy products and services are established by regulators or contractual arrangements that establish the transaction price as well as the allocation of price amongst the separate performance obligations. When preliminary regulated rates are permitted to be billed prior to final approval by the applicable regulator, certain revenue collected may be subject to refund and a liability for estimated refunds is accrued. In the event one of the parties to a contract has performed before the other, Eastern Energy Gas would recognize a contract asset or contract liability depending on the relationship between Eastern Energy Gas' performance and the customer's payment. Eastern Energy Gas has recognized contract assets of \$7 million and \$8 million as of December 31, 2024 and 2023, respectively, and \$40 million of contract liabilities as of December 31, 2024 and 2023, due to Eastern Energy Gas' performance on certain contracts. Eastern Energy Gas recognizes revenue as it fulfills its obligations to provide services to its customers. For the years ended December 31, 2024 and 2023, Eastern Energy Gas recognized revenue of \$13 million and \$52 million, respectively, from the beginning contract liability balances.

Unamortized Debt Premiums, Discounts and Debt Issuance Costs

Premiums, discounts and debt issuance costs incurred for the issuance of long-term debt are amortized over the term of the related financing using the effective interest method.

Income Taxes

Berkshire Hathaway includes Eastern Energy Gas in its consolidated U.S. federal income tax return. Consistent with established regulatory practice, Eastern Energy Gas' provision for income taxes has been computed on a stand-alone basis.

Deferred income tax assets and liabilities are based on differences between the financial statement and income tax basis of assets and liabilities using enacted income tax rates expected to be in effect for the year in which the differences are expected to reverse. Changes in deferred income tax assets and liabilities associated with components of OCI are charged or credited directly to OCI. Changes in deferred income tax assets and liabilities associated with certain property-related basis differences and other various differences that Eastern Energy Gas' regulated businesses deems probable to be passed on to its customers are charged or credited directly to a regulatory asset or liability and will be included in regulated rates when the temporary differences reverse. Other changes in deferred income tax assets and liabilities are included as a component of income tax expense. Changes in deferred income tax assets and liabilities attributable to changes in enacted income tax rates are charged or credited to income tax expense or a regulatory asset or liability in the period of enactment. Valuation allowances are established when necessary to reduce deferred income tax assets to the amount that is more-likely-than-not to be realized.

Eastern Energy Gas recognizes the tax benefit from an uncertain tax position only if it is more-likely-than-not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the Consolidated Financial Statements from such a position are measured based on the largest benefit that is more-likely-than-not to be realized upon ultimate settlement. Estimated interest and penalties, if any, related to uncertain tax positions are included as a component of income tax expense (benefit) on the Consolidated Statements of Operations.

Segment Information

Eastern Energy Gas currently has one reportable segment, which includes its natural gas transmission, storage and LNG operations. Eastern Energy Gas' chief operating decision maker ("CODM") is the BHE Pipeline Group (which consists primarily of BHE GT&S, LLC, Northern Natural Gas Company and Kern River Gas Transmission Company) President and Chief Executive Officer. The CODM uses net income attributable to Eastern Energy Gas, as reported on the Consolidated Statements of Operations, and generally considers actual results versus historical results, budgets or forecast, as well as unique risks and opportunities, when making decisions about the allocation of resources and capital. The segment expenses regularly provided to the CODM align with the captions presented on the Consolidated Statements of Operations. The measure of segment assets is reported on the Consolidated Balance Sheets as total assets.

New Accounting Pronouncements

In November 2023, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2023-07, Segment Reporting Topic 280, "Segment Reporting—Improvements to Reportable Segment Disclosures" which allows disclosure of one or more measures of segment profit or loss used by the chief operating decision maker to allocate resources and assess performance. Additionally, the standard requires enhanced disclosures of significant segment expenses and other segment items as well as incremental qualitative disclosures on both an annual and interim basis. This guidance is effective for annual reporting periods beginning after December 15, 2023, and interim reporting periods after December 15, 2024. Early adoption is permitted and retrospective application is required for all periods presented. Eastern Energy Gas adopted this guidance for the fiscal year beginning January 1, 2024 under the retrospective method. The adoption did not have a material impact on Eastern Energy Gas' Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

In December 2023, the FASB issued ASU No. 2023-09, Income Taxes Topic 740, "Income Tax—Improvements to Income Tax Disclosures" which requires enhanced disclosures, including specific categories and disaggregation of information in the effective tax rate reconciliation, disaggregated information related to income taxes paid, income or loss from continuing operations before income tax expense or benefit, and income tax expense or benefit from continuing operations. This guidance is effective for annual reporting periods beginning after December 15, 2024. Early adoption is permitted and should be applied on a prospective basis, however retrospective application is permitted. Eastern Energy Gas is currently evaluating the impact of adopting this guidance on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

In November 2024, the FASB issued ASU No. 2024-03, Income Statement—Reporting Comprehensive Income—Expense Disaggregation Disclosures Subtopic 220-40, "Disaggregation of Income Statement Expenses" which addresses requests from investors for more detailed information about certain expenses and requires disclosure of the amounts of purchases of inventory, employee compensation, depreciation and intangible asset amortization included in each relevant expense caption presented on the income statement. This guidance is effective for annual reporting periods beginning after December 15, 2026 and interim reporting periods beginning after December 15, 2027. Early adoption is permitted and should be applied on a prospective basis, however retrospective application is permitted. Eastern Energy Gas is currently evaluating the impact of adopting this guidance on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

(3) Business Acquisitions

On September 1, 2023, BHE and Eastern MLP Holding Company II, LLC ("the Buyer"), a wholly owned subsidiary of Eastern Energy Gas, completed the acquisition of DECP Holdings, Inc.'s, an indirect wholly owned subsidiary of Dominion Energy, Inc., 50% limited partner interests in Cove Point ("The Transaction"). Under the terms of the Purchase and Sale Agreement, dated July 9, 2023, the Buyer paid \$3.3 billion in cash, plus the pro rata portion of the quarterly distribution made by Cove Point for the third fiscal quarter of 2023. Eastern Energy Gas funded the Transaction through cash provided by BHE GT&S, LLC ("BHE GT&S"), which included an equity contribution of \$2.9 billion and the repayment of affiliated notes of \$474 million. The Buyer now holds 75% of the limited partner interests, and its affiliate, Cove Point GP Holding Company, LLC, continues to hold 100% of the general partner interest, of Cove Point. Prior to the Transaction, Eastern Energy Gas held 100% of the general partner interest and 25% of the limited partner interests in Cove Point. Eastern Energy Gas previously determined it has the power to direct the activities that most significantly impact Cove Point's economic performance as well as the obligation to absorb losses and benefits which could be significant to it and accordingly, consolidated Cove Point. Because Eastern Energy Gas controls Cove Point both before and after the Transaction, the changes in Eastern Energy Gas' interest in Cove Point were accounted for as an equity transaction and no gain or loss was recognized. In connection with the Transaction, Eastern Energy Gas recognized \$120 million of income taxes in equity primarily attributable to the step up in tax basis of the investment in Cove Point of \$144 million, partially offset by establishing additional regulatory liabilities related to excess deferred income taxes of \$24 million.

(4) Property, Plant and Equipment, Net

Property, plant and equipment, net consists of the following as of December 31 (in millions):

	Depreciable Life	2024	2023
Utility Plant:			
Interstate natural gas transmission assets	34 - 51 years	\$ 6,461	\$ 6,269
Storage assets	47 - 79 years	2,767	2,705
Intangible plant and other assets	4 - 53 years	482	461
Utility plant in-service		9,710	9,435
Accumulated depreciation and amortization		(3,381)	(3,201)
Utility plant in-service, net		6,329	6,234
Nonutility Plant:			
LNG facility	40 years	4,565	4,533
Accumulated depreciation and amortization		(779)	(655)
Nonutility plant, net		3,786	3,878
		10,115	10,112
Construction work- in-progress		223	231
Property, plant and equipment, net		<u>\$ 10,338</u>	<u>\$ 10,343</u>

Construction work-in-progress includes \$213 million and \$223 million as of December 31, 2024 and 2023, respectively, related to the construction of utility plant.

Assignment of Shale Development Rights

In June 2023, Eastern Gas Transmission and Storage, Inc. ("EGTS") conveyed development rights to a natural gas producer for approximately 6,500 acres of Utica Shale and Point Pleasant Formation underneath one of its natural gas storage fields and received proceeds of \$8 million and an overriding royalty interest in gas produced from the acreage. This transaction resulted in an \$8 million (\$6 million after-tax) gain, included in operations and maintenance expense in its Consolidated Statements of Operations.

(5) Jointly Owned Utility Facilities

Under joint facility ownership agreements with other utilities, Eastern Energy Gas, as a tenant in common, has undivided interests in jointly owned transmission and storage facilities. Eastern Energy Gas accounts for its proportionate share of each facility, and each joint owner has provided financing for its share of each facility. Operating costs of each facility are assigned to joint owners primarily based on their percentage of ownership. Operating costs and expenses on the Consolidated Statements of Operations include Eastern Energy Gas' share of the expenses of these facilities.

The amounts shown in the table below represent Eastern Energy Gas' share in each jointly owned facility included in property, plant and equipment, net as of December 31, 2024 (dollars in millions):

	Eastern Energy Gas' Share	Facility in Service	Accumulated Depreciation and Amortization	Construction Work-in- Progress
Ellisburg Pool	39 % \$	33 \$	13 \$	1
Ellisburg Station	50	29	9	5
Harrison	50	55	20	3
Leidy	50	148	51	4
Oakford	50	213	75	1
Total		<u>\$ 478</u>	<u>\$ 168</u>	<u>\$ 14</u>

(6) Regulatory Matters

Regulatory Assets

Regulatory assets represent costs that are expected to be recovered in future regulated rates. Eastern Energy Gas' regulatory assets reflected on the Consolidated Balance Sheets consist of the following as of December 31 (in millions):

	Weighted Average Remaining Life	2024	2023
Employee benefit plans ⁽¹⁾	10 years	\$ 24	\$ 33
Other	Various	17	21
Total regulatory assets		<u>\$ 41</u>	<u>\$ 54</u>

Reflected as:

Other current assets	\$ 11	\$ 9
Other assets	30	45
Total regulatory assets	<u>\$ 41</u>	<u>\$ 54</u>

- (1) Represents costs expected to be recovered through future rates generally over the expected remaining service period of plan participants by certain rate-regulated subsidiaries.

Eastern Energy Gas had regulatory assets not earning a return on investment of \$37 million and \$48 million as of December 31, 2024 and 2023, respectively.

Regulatory Liabilities

Regulatory liabilities represent income to be recognized or amounts expected to be returned to customers in future periods. Eastern Energy Gas' regulatory liabilities reflected on the Consolidated Balance Sheets consist of the following as of December 31 (in millions):

	Weighted Average Remaining Life	2024	2023
Deferred income taxes ⁽¹⁾	Various	\$ 416	\$ 425
Other postretirement benefit costs ⁽²⁾	Various	129	124
Cost of removal ⁽³⁾	48 years	92	85
Other	Various	19	22
Total regulatory liabilities		\$ 656	\$ 656
Reflected as:			
Current liabilities		\$ 29	\$ 33
Noncurrent liabilities		627	623
Total regulatory liabilities		\$ 656	\$ 656

- (1) Amounts primarily represent income tax liabilities related to the federal tax rate change from 35% to 21% that are probable to be passed on to customers, offset by income tax benefits related to certain property-related basis differences and other various differences that were previously passed on to customers and will be included in regulated rates when the temporary differences reverse.
- (2) Reflects a regulatory liability for the collection of postretirement benefit costs allowed in rates in excess of expense incurred.
- (3) Amounts represent estimated costs, as accrued through depreciation rates and exclusive of ARO liabilities, of removing regulated property, plant and equipment in accordance with accepted regulatory practices. Refer to Note 11 for more information.

Regulatory Matters

Carolina Gas Transmission, LLC

In November 2023, Carolina Gas Transmission, LLC ("CGT") filed a general rate case for its FERC-jurisdictional services, with proposed rates to be effective January 1, 2024. CGT's current rates were established by a 2011 settlement. CGT proposed an annual cost-of-service of \$167 million, and requested increases in various rates, including Zone 1 general system transmission rates by 84% and Zone 2 general system transmission rates by 23%. In December 2023, the FERC suspended the rate changes for five months following the proposed effective date, until June 1, 2024, subject to refund. In August 2024, a settlement agreement was filed with the FERC, resolving CGT's general rate case for its FERC-jurisdictional services and providing for increased service rates and depreciation rates. Under the terms of the settlement agreement, CGT's rates result in an average annual increase to firm transmission revenues of \$25 million over the settlement period and an increase in annual depreciation expense of \$8 million, compared to the rates in effect prior to June 1, 2024. In November 2024, the FERC approved the settlement agreement.

(7) **Investments and Restricted Cash and Cash Equivalents**

Investments and restricted cash and cash equivalents consists of the following as of December 31 (in millions):

	<u>2024</u>	<u>2023</u>
Investments:		
Investment funds	\$ 18	\$ 19
Equity method investments:		
Iroquois	243	262
Total investments	<u>261</u>	<u>281</u>
Restricted cash and cash equivalents:		
Customer deposits	27	31
Total restricted cash and cash equivalents	<u>27</u>	<u>31</u>
Total investments and restricted cash and cash equivalents	<u>\$ 288</u>	<u>\$ 312</u>
Reflected as:		
Current assets	\$ 27	\$ 31
Noncurrent assets	<u>261</u>	<u>281</u>
Total investments and restricted cash and cash equivalents	<u>\$ 288</u>	<u>\$ 312</u>

Equity Method Investments

Eastern Energy Gas, through subsidiaries, holds 50% of Iroquois, which owns and operates an interstate natural gas transmission system located in the states of New York and Connecticut.

As of December 31, 2024 and 2023, the carrying amount of Eastern Energy Gas' investments exceeded its share of underlying equity in net assets by \$130 million. The difference reflects equity method goodwill and is not being amortized. Eastern Energy Gas received distributions from its investments of \$92 million, \$73 million and \$195 million for the years ended December 31, 2024, 2023 and 2022, respectively. In the third quarter of 2022, in connection with the settlement of regulated tax matters in the Iroquois rate case, Eastern Energy Gas released a long-term regulatory liability and recognized a \$45 million benefit that was recorded in equity income (loss) in its Consolidated Statements of Operations.

(8) Long-term Debt

Eastern Energy Gas' long-term debt consists of the following, including unamortized premiums, discounts and debt issuance costs, as of December 31 (dollars and euros in millions):

	<u>Par Value</u>	<u>2024</u>	<u>2023</u>
Eastern Energy Gas:			
2.50% Senior Notes, due 2024	\$ —	\$ —	\$ 600
3.60% Senior Notes, due 2024	—	—	339
3.317% Senior Notes, due 2026 (€250) ⁽¹⁾	259	259	274
3.00% Senior Notes, due 2029	174	173	173
3.80% Senior Notes, due 2031	150	150	150
4.80% Senior Notes, due 2043	54	53	53
4.60% Senior Notes, due 2044	56	56	56
3.90% Senior Notes, due 2049	27	26	26
5.65% Senior Notes, due 2054	900	892	—
EGTS:			
3.60% Senior Notes, due 2024	—	—	111
3.00% Senior Notes, due 2029	426	423	422
5.02% Senior Notes, due 2034	150	149	—
4.80% Senior Notes, due 2043	346	342	342
4.60% Senior Notes, due 2044	444	437	437
3.90% Senior Notes, due 2049	273	271	271
Total long-term debt	<u><u>\$ 3,259</u></u>	<u><u>\$ 3,231</u></u>	<u><u>\$ 3,254</u></u>
Reflected as:			
Current portion of long-term debt		\$ —	\$ 1,050
Long-term debt		3,231	2,204
Total long-term debt		<u><u>\$ 3,231</u></u>	<u><u>\$ 3,254</u></u>

- (1) The senior notes are denominated in Euros with an outstanding principal balance of €250 million and a fixed interest rate of 1.45%. Eastern Energy Gas has entered into cross currency swaps that fix USD payments for 100% of the notes. The fixed USD outstanding principal when combined with the swaps is \$280 million, with fixed interest rates as of December 31, 2024 and 2023 that averaged 3.317%.

In January 2025, Eastern Energy Gas issued \$700 million of 5.80% Senior Notes due 2035 and \$500 million of 6.20% Senior Notes due 2055. Eastern Energy Gas used the net proceeds from the sale of the notes to rebalance its capitalization structure by returning a portion of the equity capital received from its indirect parent, BHE.

Eastern Energy Gas currently has an effective shelf registration statement with the U.S. Securities and Exchange Commission to issue an additional \$400 million of long-term debt securities through January 11, 2027.

Annual Payment on Long-Term Debt

The annual repayments of long-term debt for the years beginning January 1, 2025 and thereafter, are as follows (in millions):

2025	\$	—
2026		259
2027		—
2028		—
2029		600
2030 and thereafter		2,400
Total		3,259
Unamortized premium, discount and debt issuance cost		(28)
Total	\$	<u>3,231</u>

(9) Income Taxes

Income tax expense (benefit) consists of the following for the years ended December 31 (in millions):

	2024	2023	2022
Current:			
Federal	\$ 44	\$ (236)	\$ 12
State	29	(7)	29
	<u>73</u>	<u>(243)</u>	<u>41</u>
Deferred:			
Federal	112	357	88
State	15	(4)	38
	<u>127</u>	<u>353</u>	<u>126</u>
Total	<u>\$ 200</u>	<u>\$ 110</u>	<u>\$ 167</u>

A reconciliation of the federal statutory income tax rate to the effective income tax rate applicable to income before income tax expense (benefit) is as follows for the years ended December 31:

	2024	2023	2022
Federal statutory income tax rate	21 %	21 %	21 %
State income tax, net of federal income tax benefit	4	(1)	6
Equity interest	2	2	2
Effects of ratemaking	—	—	(1)
Noncontrolling interest	(3)	(9)	(10)
Effective income tax rate	<u>24 %</u>	<u>13 %</u>	<u>18 %</u>

The net deferred income tax liability consists of the following as of December 31 (in millions):

	2024	2023
Deferred income tax assets:		
Federal and state carryforwards	\$ 27	\$ 22
Employee benefits	25	29
Intangibles	84	98
Derivatives and hedges	11	13
Deferred state income taxes	22	24
Regulatory liabilities	10	1
Other	2	3
Total deferred income tax assets	181	190
Deferred income tax liabilities:		
Property-related items	(410)	(343)
Partnership investments	(211)	(158)
Debt exchange	(47)	(50)
Regulatory assets	(6)	(1)
Other	(4)	(4)
Total deferred income tax liabilities	(678)	(556)
Net deferred income tax liability ⁽¹⁾	<u>\$ (497)</u>	<u>\$ (366)</u>

(1) As of December 31, 2024 and 2023, net federal deferred income tax liability is presented in noncurrent liabilities and net state deferred income tax asset is presented in other assets in the Consolidated Balance Sheets.

As of December 31, 2024, Eastern Energy Gas' state tax carryforwards, entirely related to \$27 million of net operating losses, expire at various intervals between 2036 and indefinite.

The U.S. Internal Revenue Service has not closed or effectively settled an examination of Eastern Energy Gas' income tax returns for any tax years beginning on or after November 1, 2020. The statute of limitations for Eastern Energy Gas' states remains open for periods beginning on or after November 1, 2020. The closure of examinations, or the expiration of the statute of limitations, for state filings may not preclude the state from adjusting the state net operating loss carryforward utilized in a year for which the statute of limitations is not closed.

(10) Employee Benefit Plans

Defined Benefit Plans

Eastern Energy Gas is a participant in benefit plans sponsored by MidAmerican Energy Company ("MidAmerican Energy"), an affiliate. The MidAmerican Energy Company Retirement Plan includes a qualified pension plan ("Qualified Pension Plan") that provides pension benefits for eligible employees. The MidAmerican Energy Company Welfare Benefit Plan provides certain postretirement health care and life insurance benefits for eligible retirees ("Other Postretirement Plans") on behalf of Eastern Energy Gas. Eastern Energy Gas made \$7 million, \$8 million and \$14 million of contributions to the MidAmerican Energy Company Retirement Plan for the years ended December 31, 2024, 2023 and 2022, respectively. Eastern Energy Gas made \$2 million of contributions to the MidAmerican Energy Company Welfare Benefit Plan for the years ended December 31, 2024, 2023 and 2022. Contributions related to these plans are reflected as net periodic benefit cost in operations and maintenance expense in the Consolidated Statements of Operations. Amounts attributable to Eastern Energy Gas were allocated from MidAmerican Energy in accordance with the intercompany administrative service agreement. Offsetting regulatory assets and liabilities have been recorded related to the amounts not yet recognized as a component of net periodic benefit costs that will be included in regulated rates. Net periodic benefit costs not included in regulated rates are included in accumulated other comprehensive loss, net.

Defined Contribution Plan

Eastern Energy Gas participates in the MidAmerican Energy defined contribution plan. Eastern Energy Gas' matching contributions are based on each participant's level of contribution. Contributions cannot exceed the maximum allowable for tax purposes. Beginning April 1, 2023, certain participants receive enhanced benefits in the plan and no longer accrue benefits in the noncontributory defined benefit pension plans. Eastern Energy Gas' contributions to the plans were \$14 million, \$12 million and \$6 million for the years ended December 31, 2024, 2023 and 2022, respectively.

(11) Asset Retirement Obligations

Eastern Energy Gas estimates its ARO liabilities based upon detailed engineering calculations of the amount and timing of the future cash spending for a third party to perform the required work. Spending estimates are escalated for inflation and then discounted at a credit-adjusted, risk-free rate. Changes in estimates could occur for a number of reasons, including changes in laws and regulations, plan revisions, inflation and changes in the amount and timing of the expected work.

Eastern Energy Gas does not recognize liabilities for AROs for which the fair value cannot be reasonably estimated. Due to the indeterminate removal date, the fair value of the associated liabilities on the Cove Point LNG facility, interim removal of natural gas pipelines and certain storage wells in EGTS' underground natural gas storage network cannot currently be estimated, and no amounts are recognized on the Consolidated Financial Statements other than those included in the cost of removal regulatory liability established via approved depreciation rates in accordance with accepted regulatory practices. These accruals totaled \$92 million and \$85 million as of December 31, 2024 and 2023, respectively.

The following table reconciles the beginning and ending balances of Eastern Energy Gas' ARO liabilities for the years ended December 31 (in millions):

	2024	2023
Beginning balance	\$ 30	\$ 48
Retirements	(3)	(19)
Accretion	1	1
Ending balance	<u>\$ 28</u>	<u>\$ 30</u>
Reflected as:		
Other current liabilities	\$ 3	\$ 5
Other long-term liabilities	25	25
Total ARO liability	<u>\$ 28</u>	<u>\$ 30</u>

(12) Risk Management and Hedging Activities

Eastern Energy Gas is exposed to the impact of market fluctuations in commodity prices, interest rates, and foreign currency exchange rates. Eastern Energy Gas is principally exposed to natural gas market fluctuations primarily through fuel retained and used during the operation of the pipeline system, to interest rate risk on its outstanding variable-rate short-term debt and future debt issuances, and to foreign currency exchange risk associated with Euro denominated debt. Eastern Energy Gas has established a risk management process that is designed to identify, assess, manage and report on each of the various types of risk involved in its business. To mitigate a portion of its commodity price risk, Eastern Energy Gas uses commodity derivative contracts, which may include forwards, futures, options, swaps and other agreements, to effectively secure future supply or sell future production generally at fixed prices. Eastern Energy Gas also uses interest rate swaps to hedge its exposure to variable interest rates on long-term debt as well as foreign currency swaps to hedge its exposure to principal and interest payments denominated in Euros. Eastern Energy Gas does not hedge all of its commodity price and interest rate risks, thereby exposing the unhedged portion to changes in market prices.

There have been no significant changes in Eastern Energy Gas' accounting policies related to derivatives. Refer to Notes 2 and 13 for additional information on derivative contracts.

Derivative Contract Volumes

The following table summarizes the combined absolute value of long and short positions of outstanding commodity and foreign currency derivative contracts with fixed price terms that comprise the mark-to-market values as of December 31 (in millions):

	Unit of Measure	2024	2023
Foreign currency	Euro €	250	250
Natural gas	Dth	—	6

Credit Risk

Eastern Energy Gas is exposed to counterparty credit risk associated with wholesale energy supply and marketing activities with other utilities, energy marketing companies, financial institutions and other market participants. Credit risk may be concentrated to the extent Eastern Energy Gas' counterparties have similar economic, industry or other characteristics and due to direct or indirect relationships among the counterparties. Before entering into a transaction, Eastern Energy Gas analyzes the financial condition of each significant wholesale counterparty, establishes limits on the amount of unsecured credit to be extended to each counterparty and evaluates the appropriateness of unsecured credit limits on an ongoing basis. To further mitigate wholesale counterparty credit risk, Eastern Energy Gas enters into netting and collateral arrangements that may include margining and cross-product netting agreements and obtains third-party guarantees, letters of credit and cash deposits. If required, Eastern Energy Gas exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

The majority of Cove Point's revenue and earnings are from annual reservation payments under certain terminalling, storage and transmission contracts with ST Cove Point, LLC, a joint venture of Sumitomo Corporation and Tokyo Gas Co., LTD., and GAIL Global (USA) LNG, LLC (the "Export Customers"). If such agreements were terminated and Cove Point was unable to replace such agreements on comparable terms, there could be a material impact on results of operations, financial condition and/or cash flows.

The Export Customers comprised approximately 39% and 38% of Eastern Energy Gas' operating revenues for the years ended December 31, 2024 and 2023, respectively, with Eastern Energy Gas' largest customer representing approximately 20% and 19% of such amounts, respectively.

For the year ended December 31, 2024, EGTS provided operational service to 252 customers with approximately 95% of its storage and transmission revenue being provided through firm services. The 10 largest customers provided approximately 41% of EGTS' total storage and transmission revenue and the thirty largest provided approximately 72% of EGTS' total storage and transmission revenue.

(13) Fair Value Measurements

The carrying value of Eastern Energy Gas' cash, certain cash equivalents, receivables, payables, accrued liabilities and short-term borrowings approximates fair value because of the short-term maturity of these instruments. Eastern Energy Gas has various financial assets and liabilities that are measured at fair value on the Consolidated Financial Statements using inputs from the three levels of the fair value hierarchy. A financial asset or liability classification within the hierarchy is determined based on the lowest level input that is significant to the fair value measurement. The three levels are as follows:

- Level 1 - Inputs are unadjusted quoted prices in active markets for identical assets or liabilities that Eastern Energy Gas has the ability to access at the measurement date.
- Level 2 - Inputs include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived principally from or corroborated by observable market data by correlation or other means (market corroborated inputs).
- Level 3 - Unobservable inputs reflect Eastern Energy Gas' judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. Eastern Energy Gas develops these inputs based on the best information available, including its own data.

The following table presents Eastern Energy Gas' financial assets and liabilities recognized on the Consolidated Balance Sheets and measured at fair value on a recurring basis (in millions):

	Input Levels for Fair Value Measurements			
	Level 1	Level 2	Level 3	Total
As of December 31, 2024				
Assets:				
Money market mutual funds	\$ 34	\$ —	\$ —	\$ 34
Equity securities:				
Investment funds	18	—	—	18
	<u>\$ 52</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 52</u>
Liabilities:				
Foreign currency exchange rate derivatives	\$ —	\$ (23)	\$ —	\$ (23)
	<u>\$ —</u>	<u>\$ (23)</u>	<u>\$ —</u>	<u>\$ (23)</u>
As of December 31, 2023				
Assets:				
Money market mutual funds	\$ 62	\$ —	\$ —	\$ 62
Equity securities:				
Investment funds	19	—	—	19
	<u>\$ 81</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 81</u>
Liabilities:				
Foreign currency exchange rate derivatives	\$ —	\$ (8)	\$ —	\$ (8)
	<u>\$ —</u>	<u>\$ (8)</u>	<u>\$ —</u>	<u>\$ (8)</u>

Eastern Energy Gas' investments in money market mutual funds and investment funds are stated at fair value. When available, a readily observable quoted market price or net asset value of an identical security in an active market is used to record the fair value.

Derivative contracts are recorded on the Consolidated Balance Sheets as either assets or liabilities and are stated at estimated fair value unless they are designated as normal purchase or normal sales and qualify for the exception afforded by GAAP. When available, the fair value of derivative contracts is estimated using unadjusted quoted prices for identical contracts in the market in which Eastern Energy Gas transacts. When quoted prices for identical contracts are not available, Eastern Energy Gas uses forward price curves. Forward price curves represent Eastern Energy Gas' estimates of the prices at which a buyer or seller could contract today for delivery or settlement at future dates. Eastern Energy Gas bases its forward price curves upon market price quotations, when available, or internally developed and commercial models, with internal and external fundamental data inputs. Market price quotations are obtained from independent brokers, exchanges, direct communication with market participants and actual transactions executed by Eastern Energy Gas. Market price quotations are generally readily obtainable for the applicable term of Eastern Energy Gas' outstanding derivative contracts; therefore, Eastern Energy Gas' forward price curves reflect observable market quotes. Market price quotations for certain natural gas trading hubs are not as readily obtainable due to the length of the contracts. Given that limited market data exists for these contracts, as well as for those contracts that are not actively traded, Eastern Energy Gas uses forward price curves derived from internal models based on perceived pricing relationships to major trading hubs that are based on unobservable inputs. The estimated fair value of these derivative contracts is a function of underlying forward commodity prices, interest rates, currency rates, related volatility, counterparty creditworthiness and duration of contracts.

Eastern Energy Gas' long-term debt is carried at cost, including unamortized premiums, discounts and debt issuance costs as applicable, on the Consolidated Financial Statements. The fair value of Eastern Energy Gas' long-term debt is a Level 2 fair value measurement and has been estimated based upon quoted market prices, where available, or at the present value of future cash flows discounted at rates consistent with comparable maturities with similar credit risks. The following table presents the carrying value and estimated fair value of Eastern Energy Gas' long-term debt as of December 31 (in millions):

	2024		2023	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	\$ 3,231	\$ 2,919	\$ 3,254	\$ 2,968

(14) Commitments and Contingencies

Environmental Laws and Regulations

Eastern Energy Gas is subject to federal, state and local laws and regulations regarding air quality, climate change, emissions performance standards, water quality and other environmental matters that have the potential to impact its current and future operations. Eastern Energy Gas believes it is in material compliance with all applicable laws and regulations.

Legal Matters

Eastern Energy Gas is party to a variety of legal actions arising out of the normal course of business. Eastern Energy Gas does not believe that such normal and routine litigation will have a material impact on its consolidated financial results.

Surety Bonds

As of December 31, 2024, Eastern Energy Gas had purchased \$17 million of surety bonds. Under the terms of the surety bonds, Eastern Energy Gas is obligated to indemnify the respective surety bond company for any amounts paid.

(15) Revenue from Contracts with Customers

The following table summarizes Eastern Energy Gas' Customer Revenue by regulated and nonregulated, with further disaggregation of regulated by line of business, for the years ended December 31 (in millions):

	2024	2023	2022
Customer Revenue:			
Regulated:			
Gas transmission and storage	\$ 1,197	\$ 1,210	\$ 1,179
Wholesale	7	22	8
Other	1	5	1
Total regulated	1,205	1,237	1,188
Nonregulated	802	818	821
Total Customer Revenue	2,007	2,055	2,009
Other revenue ⁽¹⁾	4	4	(3)
Total operating revenue	\$ 2,011	\$ 2,059	\$ 2,006

- (1) Other revenue consists primarily of revenue recognized in accordance with Accounting Standards Codification ("ASC") 815, "Derivative and Hedging" which includes unrealized gains and losses for derivatives not designated as hedges related to natural gas sales contracts, contingent fees from certain farmout agreements recognized in accordance with ASC 450, "Contingencies" and the royalties from the conveyance of mineral rights accounted for under ASC 932 "Extractive Activities – Oil and Gas".

Remaining Performance Obligations

The following table summarizes Eastern Energy Gas' revenue it expects to recognize in future periods related to significant unsatisfied remaining performance obligations for fixed contracts with expected durations in excess of one year as of December 31, 2024 (in millions):

	Performance obligations expected to be satisfied		Total
	Less than 12 months	More than 12 months	
Eastern Energy Gas	\$ 1,702	\$ 13,907	\$ 15,609

(16) Components of Accumulated Other Comprehensive Loss, Net

The following table shows the change in accumulated other comprehensive loss by each component of other comprehensive income (loss), net of applicable income taxes, for the year ended December 31 (in millions):

	Unrecognized Amounts On Retirement Benefits	Unrealized Losses On Cash Flow Hedges	Noncontrolling Interests	Accumulated Other Comprehensive Loss, Net
Balance, December 31, 2021	\$ (6)	\$ (42)	\$ 5	\$ (43)
Other comprehensive income (loss)	5	(1)	(3)	1
Balance, December 31, 2022	(1)	(43)	2	(42)
Other comprehensive (loss) income	(2)	5	—	3
Purchase of noncontrolling interest	—	—	(1)	(1)
Balance, December 31, 2023	(3)	(38)	1	(40)
Other comprehensive income	1	4	—	5
Balance, December 31, 2024	<u>\$ (2)</u>	<u>\$ (34)</u>	<u>\$ 1</u>	<u>\$ (35)</u>

The following table shows the reclassifications from AOCI to net income for the year ended December 31 (in millions):

	Amounts Reclassified From AOCI	Affected Line Item In The Consolidated Statements of Operations
2024		
Deferred (gains) and losses on derivatives-hedging activities:		
Interest rate contracts	\$ 3	Interest expense
Foreign currency contracts	17	Other, net
Total	20	
Tax	(5)	Income tax expense (benefit)
Total, net of tax	\$ 15	
2023		
Deferred (gains) and losses on derivatives-hedging activities:		
Interest rate contracts	\$ 3	Interest expense
Foreign currency contracts	(8)	Other, net
Total	(5)	
Tax	1	Income tax expense (benefit)
Total, net of tax	\$ (4)	
2022		
Deferred (gains) and losses on derivatives-hedging activities:		
Interest rate contracts	\$ 3	Interest expense
Foreign currency contracts	1	Other, net
Total	4	
Tax	(1)	Income tax expense (benefit)
Total, net of tax	\$ 3	

The following table presents selected information related to losses on cash flow hedges included in AOCI in Eastern Energy Gas' Consolidated Balance Sheet as of December 31, 2024 (in millions):

	AOCI After-Tax	Amounts Expected to be Reclassified to Earnings During the Next 12 Months After-Tax	Maximum Term
Interest rate	\$ (33)	\$ (3)	240 months
Foreign currency	(1)	(4)	18 months
Total	\$ (34)	\$ (7)	

The amounts that will be reclassified from AOCI to earnings will generally be offset by the recognition of the hedged transactions (e.g., interest payments) in earnings, thereby achieving the realization of prices contemplated by the underlying risk management strategies and will vary from the expected amounts presented above as a result of changes in interest rates and foreign currency exchange rates.

(17) Variable Interest Entities and Noncontrolling Interests

The primary beneficiary of a VIE is required to consolidate the VIE and to disclose certain information about its significant variable interests in the VIE. The primary beneficiary of a VIE is the entity that has both 1) the power to direct the activities that most significantly impact the entity's economic performance and 2) the obligation to absorb losses or receive benefits from the entity that could potentially be significant to the VIE.

As of December 31, 2024, Eastern Energy Gas holds 75% of the limited partner interest and holds 100% of the general partner interest of Cove Point. Eastern Energy Gas concluded that Cove Point is a VIE due to the limited partner lacking the characteristics of a controlling financial interest. Eastern Energy Gas is the primary beneficiary of Cove Point as it has the power to direct the activities that most significantly impact its economic performance as well as the obligation to absorb losses and benefits which could be significant to it.

Eastern Energy Gas purchased shared services from Carolina Gas Services, Inc. ("Carolina Gas Services") an affiliated VIE, of \$3 million and \$12 million for the years ended December 31, 2023 and 2022, respectively. Effective April 2023, Carolina Gas Services no longer provides services to Eastern Energy Gas. Eastern Energy Gas determined that neither it nor any of its consolidated entities was the primary beneficiary of Carolina Gas Services as neither it nor any of its consolidated entities had both the power to direct the activities that most significantly impacted its economic performance as well as the obligation to absorb losses and benefits which could be significant to them. Carolina Gas Services provided marketing and operational services. Neither Eastern Energy Gas nor any of its consolidated entities had any obligation to absorb more than its allocated share of Carolina Gas Services costs.

Included in noncontrolling interests in the Consolidated Financial Statements are Dominion Energy Inc.'s 50% interest in Cove Point (through August 2023) and Brookfield Super-Core Infrastructure Partner's 25% interest in Cove Point.

(18) Supplemental Cash Flow Disclosures

The summary of supplemental cash flow disclosures as of and for the years ended December 31 is as follows (in millions):

	2024	2023	2022
Supplemental disclosure of cash flow information:			
Interest paid, net of amounts capitalized	\$ 130	\$ 144	\$ 143
Income taxes paid, net	\$ —	\$ 5	\$ 2
Supplemental disclosure of non-cash investing and financing transactions:			
Accruals related to property, plant and equipment additions	\$ 10	\$ 18	\$ 29
Equity distributions ⁽¹⁾	\$ (322)	\$ (224)	\$ (42)
Equity contributions ⁽¹⁾	\$ 119	\$ 38	\$ 98

(1) Amounts primarily represent the forgiveness of affiliated receivables/payables.

(19) Related Party Transactions

Eastern Energy Gas is party to a tax-sharing agreement and is part of the Berkshire Hathaway consolidated U.S. federal income tax return. For current federal and state income taxes, Eastern Energy Gas had a payable to BHE of \$188 million as of December 31, 2024 and a receivable from BHE of \$67 million as of December 31, 2023.

Presented below are Eastern Energy Gas' significant transactions with affiliated and related parties for the years ended December 31 (in millions):

	2024	2023	2022
Sales of natural gas and transmission and storage services	\$ 4	\$ 5	\$ 27
Purchases of natural gas and transmission and storage services	—	—	4
Services provided by related parties ⁽¹⁾	58	99	83
Services provided to related parties	30	35	38

(1) Includes capitalized expenditures.

Eastern Energy Gas participates in certain MidAmerican Energy benefit plans as described in Note 10. As of December 31, 2024 and 2023, Eastern Energy Gas' amount due to MidAmerican Energy associated with these plans and reflected in other long-term liabilities on the Consolidated Balance Sheets was \$39 million and \$53 million, respectively.

Borrowings with BHE GT&S

Eastern Energy Gas has a \$400 million intercompany revolving credit agreement from its parent, BHE GT&S, expiring in March 2026. The credit agreement, which is for general corporate purposes and provides for the issuance of letters of credit, has a variable interest rate based on the Secured Overnight Financing Rate ("SOFR") plus a fixed spread. Net outstanding borrowings totaled \$400 million with a weighted-average interest rate of 5.84% as of December 31, 2023. There were no amounts outstanding under the credit agreement as of December 31, 2024. Interest expense related to the credit agreement totaled \$8 million and \$4 million for the years ended December 31, 2024 and 2023, respectively.

BHE GT&S has a \$650 million intercompany revolving credit agreement from Eastern Energy Gas expiring in November 2025. The credit agreement has a variable interest rate based on SOFR plus a fixed spread. There were no amounts outstanding under the credit agreement as of December 31, 2024 and 2023. Interest income related to the credit agreement totaled \$2 million, \$20 million and \$7 million for the years ended December 31, 2024, 2023 and 2022, respectively.

Eastern Gas Transmission and Storage, Inc. and its subsidiaries
Consolidated Financial Section

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

The following is management's discussion and analysis of certain significant factors that have affected the consolidated financial condition and results of operations of EGTS during the periods included herein. This discussion should be read in conjunction with EGTS' historical Consolidated Financial Statements and Notes to Consolidated Financial Statements in Item 8 of this Form 10-K. EGTS' actual results in the future could differ significantly from the historical results.

Results of Operations

Overview

Net income for the year ended December 31, 2024 was \$256 million, an increase of \$18 million, or 8%, compared to 2023, primarily due to lower technology and related charges, lower outside services due to the termination of Dominion Energy, Inc.'s transition services agreement and higher margin from regulated gas transmission and storage operations of \$4 million, partially offset by a gain in 2023 from an agreement to convey development rights underneath one of its natural gas storage fields.

Net income for the year ended December 31, 2023 was \$238 million, a decrease of \$23 million, or 9%, compared to 2022, primarily due to lower margin from regulated gas transmission and storage operations of \$20 million, an increase in salary and benefits expense and higher technology and related charges, partially offset by lower income tax expense primarily due to favorable state tax adjustments.

Year Ended December 31, 2024 Compared to Year Ended December 31, 2023

Operating revenue decreased \$27 million, or 3%, for 2024 compared to 2023, primarily due to a decrease in variable revenue related to park and loan activity of \$18 million, a decrease in regulated gas sales for operational and system balancing purposes due to decreased prices and volumes of \$15 million and a decrease in services provided to affiliates of \$7 million, partially offset by an increase in regulated gas transmission and storage services revenues primarily due to higher volumes of \$17 million.

Cost of (excess) gas decreased \$31 million, or 82%, for 2024 compared to 2023, primarily due to the unfavorable revaluation of volumes retained in 2023.

Operations and maintenance decreased \$20 million, or 5%, for 2024 compared to 2023, primarily due to lower technology and related charges of \$14 million, lower outside services of \$7 million due to the termination of Dominion Energy Inc.'s transition services agreement and a decrease in services provided to affiliates of \$7 million, partially offset by a gain in 2023 from an agreement to convey development rights underneath one of its natural gas storage fields of \$8 million.

Other, net increased \$4 million for 2024 compared to 2023, largely due to ARO settlement gains resulting from the FERC order in late 2023 finalizing the remediation activities for the Supply Header Project.

Income tax expense increased \$8 million, or 10%, for 2024 compared to 2023 and the effective tax rate was 25% in 2024 and 2023.

Year Ended December 31, 2023 Compared to Year Ended December 31, 2022

Operating revenue increased \$51 million, or 5%, for 2023 compared to 2022, primarily due to an increase in regulated gas transmission and storage services revenues primarily due to the settlement of EGTS' general rate case of \$49 million, an increase in variable revenue related to park and loan activity of \$17 million and an increase in regulated gas sales for operational and system balancing purposes primarily due to increased volumes of \$15 million, partially offset by a net decrease in regulated gas transmission and storage services revenues due to volumes primarily from the expiration of the Appalachian Gateway Project contracts in August 2022 of \$29 million.

Cost of (excess) gas was an expense of \$38 million for 2023 compared to a credit of \$33 million for 2022. The change is primarily from a decrease from other operational and system balancing fuel activities prior to the effective date of the new fuel tracker due to the settlement of EGTS' general rate case of \$45 million and the unfavorable revaluation of the volumes retained prior to the effective date of the new fuel tracker due to lower natural gas prices of \$27 million.

Operations and maintenance increased \$40 million, or 11%, for 2023 compared to 2022, primarily due to an increase in salaries, wages and benefits of \$23 million, higher technology and related charges of \$13 million and an increase in operational materials and services of \$3 million, partially offset by a gain from an agreement to convey development rights underneath one of its natural gas storage fields of \$8 million.

Depreciation and amortization decreased \$1 million, or 1%, for 2023 compared to 2022, primarily due to the settlement of depreciation rates in EGTS' general rate case of \$8 million, partially offset by higher plant placed in-service of \$7 million.

Property and other taxes decreased \$4 million, or 7%, for 2023 compared to 2022, primarily due to lower than estimated 2022 tax assessments.

Other, net was income of \$1 million for 2023 compared to an expense of \$2 million in 2022. The change is primarily from gains on marketable securities.

Income tax expense decreased \$30 million, or 28%, for 2023 compared to 2022 and the effective tax rate was 25% in 2023 and 29% in 2022. The effective tax rate decreased primarily due to the reduction in the state effective rate.

Liquidity and Capital Resources

As of December 31, 2024, EGTS' total net liquidity was as follows (in millions):

Cash and cash equivalents	\$	8
Intercompany revolving credit agreement ⁽¹⁾		400
Total net liquidity	\$	408
Intercompany revolving credit agreement:		
Maturity date		2026

(1) Refer to Note 17 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for further discussion regarding EGTS' intercompany revolving credit agreement.

Operating Activities

Net cash flows from operating activities for the years ended December 31, 2024 and 2023 were \$497 million and \$418 million, respectively. The change was primarily due to the repayment of EGTS rate refunds to customers in 2023 and other changes in working capital.

Net cash flows from operating activities for the years ended December 31, 2023 and 2022 were \$418 million and \$552 million, respectively. The change was primarily due to the repayment of EGTS rate refunds to customers and the timing of income tax payments, partially offset by other changes in working capital.

Investing Activities

Net cash flows from investing activities for the years ended December 31, 2024 and 2023 were \$(251) million and \$(237) million, respectively. The change was primarily due to an increase in notes to affiliates of \$25 million, an increase in capital expenditures of \$14 million and proceeds from the assignment of shale development rights in 2023 of \$8 million, partially offset by an increase in repayments of notes by affiliates of \$25 million, an increase in proceeds from sales of marketable securities of \$3 million a decrease in purchases of marketable securities of \$3 million.

Net cash flows from investing activities for the years ended December 31, 2023 and 2022 were \$(237) million and \$(286) million, respectively. The change was primarily due to a decrease in capital expenditures of \$34 million, proceeds from the assignment of shale development rights of \$8 million and a decrease in notes to affiliates of \$8 million, partially offset by a decrease in repayments of notes by affiliates of \$11 million.

Financing Activities

Net cash flows from financing activities for the year ended December 31, 2024 were \$(248) million. Sources of cash totaled \$162 million and consisted of proceeds from the issuance of long-term debt of \$149 million and proceeds from equity contributions from Eastern Energy Gas of \$13 million. Uses of cash totaled \$410 million and consisted of dividends paid to Eastern Energy Gas of \$297 million, repayment of long-term debt of \$111 million and net repayment of notes payable to Eastern Energy Gas of \$2 million.

Net cash flows from financing activities for the year ended December 31, 2023 were \$(192) million and consisted of dividends paid to Eastern Energy Gas of \$158 million and net repayment of notes payable to Eastern Energy Gas of \$34 million.

Net cash flows from financing activities for the year ended December 31, 2022 were \$(247) million and consisted of dividends paid to Eastern Energy Gas of \$215 million and net repayment of notes payable to Eastern Energy Gas of \$32 million.

Short-term Debt

As of December 31, 2023, EGTS had \$2 million of an outstanding note payable to an affiliate at a weighted average interest rate of 5.41%. There were no amounts outstanding under the credit agreement as of December 31, 2024. For further discussion, refer to Note 17 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Future Uses of Cash

Capital Expenditures

Capital expenditure needs are reviewed regularly by management and may change significantly as a result of these reviews, which may consider, among other factors, new growth projects and the timing of growth projects; changes in environmental and other rules and regulations; impacts to customers' rates; outcomes of regulatory proceedings; changes in income tax laws; general business conditions; system reliability standards; the cost and efficiency of construction labor, equipment and materials; commodity prices; and the cost and availability of capital.

EGTS' historical and forecasted capital expenditures, each of which exclude amounts for non-cash equity AFUDC and other non-cash items, for the years ending December 31 are as follows (in millions):

	Historical			Forecast		
	2022	2023	2024	2025	2026	2027
Natural gas transmission and storage	\$ 35	\$ 16	\$ 34	\$ 51	\$ 68	\$ 215
Other	240	225	221	226	274	179
Total	<u>\$ 275</u>	<u>\$ 241</u>	<u>\$ 255</u>	<u>\$ 277</u>	<u>\$ 342</u>	<u>\$ 394</u>

EGTS' natural gas transmission and storage capital expenditures primarily include growth capital expenditures related to planned regulated projects. EGTS' other capital expenditures consist primarily of pipeline integrity work, automation and controls upgrades, underground storage, corrosion control, unit exchanges, compressor modifications and projects related to Pipeline Hazardous Materials Safety Administration natural gas storage rules. The amounts also include EGTS' asset modernization program, which includes projects for vintage pipeline replacement, compression replacement, pipeline assessment and underground storage integrity.

Material Cash Requirements

The following table summarizes EGTS' material cash requirements as of December 31, 2024 (in millions):

	Payments Due by Periods				
	2025	2026-2027	2028-2029	2030 and thereafter	Total
Interest payments on long-term debt ⁽¹⁾	\$ 68	\$ 136	\$ 136	\$ 790	\$ 1,130
Natural gas supply and transmission ⁽¹⁾	46	94	94	47	281
Total cash requirements	<u>\$ 114</u>	<u>\$ 230</u>	<u>\$ 230</u>	<u>\$ 837</u>	<u>\$ 1,411</u>

(1) Not reflected on the Consolidated Balance Sheets.

In addition, EGTS also has cash requirements that may affect its consolidated financial condition that arise from operating leases (refer to Note 5), long-term debt (refer to Note 8), construction and other development costs (refer to Liquidity and Capital Resources included within this Item 7), uncertain tax positions (refer to Note 9) and AROs (refer to Note 11). Refer, where applicable, to the respective referenced note in Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

Regulatory Matters

EGTS is subject to comprehensive regulation. Refer to the discussion contained in Item 1 of this Form 10-K for further information regarding EGTS' general regulatory framework and current regulatory matters.

Environmental Laws and Regulations

EGTS is subject to federal, state and local laws and regulations regarding air quality, climate change, emissions performance standards, water quality and other environmental matters that have the potential to impact its current and future operations. In addition to imposing continuing compliance obligations and capital expenditure requirements, these laws and regulations provide regulators with the authority to levy substantial penalties for noncompliance, including fines, injunctive relief and other sanctions. These laws and regulations are administered by various federal, state and local agencies. EGTS believes it is in material compliance with all applicable laws and regulations, although many laws and regulations are subject to interpretation that may ultimately be resolved by the courts. Environmental laws and regulations continue to evolve, and EGTS is unable to predict the impact of the changing laws and regulations on its operations and financial results.

Refer to "Environmental Laws and Regulations" in Item 1 of this Form 10-K for further discussion regarding environmental laws and regulations.

Collateral and Contingent Features

Debt of EGTS is rated by credit rating agencies. Assigned credit ratings are based on each rating agency's assessment of EGTS' ability to, in general, meet the obligations of its issued debt. The credit ratings are not a recommendation to buy, sell or hold securities, and there is no assurance that a particular credit rating will continue for any given period of time.

EGTS has no credit rating downgrade triggers that would accelerate the maturity dates of outstanding debt, and a change in ratings is not an event of default under the applicable debt instruments.

Inflation

Historically, overall inflation and changing prices in the economies where EGTS operates have not had a significant impact on EGTS' consolidated financial results. EGTS operates under cost-of-service based rate-setting structures administered by the FERC. Under these rate-setting structures, EGTS is allowed to include prudent costs in its rates, including the impact of inflation. EGTS attempts to minimize the potential impact of inflation on its operations by employing prudent risk management and hedging strategies and by considering, among other areas, its impact on purchases of energy, operating expenses, materials and equipment costs, contract negotiations, future capital spending programs and long-term debt issuances. There can be no assurance that such actions will be successful.

New Accounting Pronouncements

For a discussion of new accounting pronouncements affecting EGTS, refer to Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Critical Accounting Estimates

Certain accounting measurements require management to make estimates and judgments concerning transactions that will be settled several years in the future. Amounts recognized on the Consolidated Financial Statements based on such estimates involve numerous assumptions subject to varying and potentially significant degrees of judgment and uncertainty and will likely change in the future as additional information becomes available. The following critical accounting estimates are impacted significantly by EGTS' methods, judgments and assumptions used in the preparation of the Consolidated Financial Statements and should be read in conjunction with EGTS' Summary of Significant Accounting Policies included in EGTS' Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Accounting for the Effects of Certain Types of Regulation

EGTS prepares its Consolidated Financial Statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, EGTS defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in regulated rates occur.

EGTS continually evaluates the applicability of the guidance for regulated operations and whether its regulatory assets and liabilities are probable of inclusion in future regulated rates by considering factors such as a change in the regulator's approach to setting rates from cost-based ratemaking to another form of regulation, other regulatory actions or the impact of competition that could limit EGTS' ability to recover its costs. EGTS believes its application of the guidance for regulated operations is appropriate and its existing regulatory assets and liabilities are probable of inclusion in future regulated rates. The evaluation reflects the current political and regulatory climate at the federal level. If it becomes no longer probable that the deferred costs or income will be included in future regulated rates, the related regulatory assets and liabilities will be recognized in net income, returned to customers or re-established as AOCI. Total regulatory assets were \$31 million and total regulatory liabilities were \$540 million as of December 31, 2024. Refer to EGTS' Note 6 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding EGTS' regulatory assets and liabilities.

Impairment of Long-Lived Assets

EGTS evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or when the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value and any resulting impairment loss is reflected on the Consolidated Statements of Operations. As substantially all property, plant and equipment supports EGTS' regulated businesses, the impacts of regulation are considered when evaluating the carrying value of regulated assets.

The estimate of cash flows arising from the future use of an asset, for the purposes of impairment analysis, requires the exercise of judgment. Circumstances that could significantly alter the calculation of fair value or the recoverable amount of an asset may include significant changes in the regulatory environment, the business climate, management's plans, legal factors, market price of the asset, the use of the asset, the physical condition of the asset, future market prices, competition and many other factors over the life of the asset. Any resulting impairment loss is highly dependent on the underlying assumptions and could significantly affect EGTS' results of operations.

Income Taxes

In determining EGTS' income taxes, management is required to interpret complex income tax laws and regulations, which includes consideration of regulatory implications imposed by the FERC. EGTS' income tax returns are subject to continuous examinations by federal, state and local income tax authorities that may give rise to different interpretations of these complex laws and regulations. Due to the nature of the examination process, it generally takes years before these examinations are completed and these matters are resolved. EGTS recognizes the tax benefit from an uncertain tax position only if it is more-likely-than-not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the Consolidated Financial Statements from such a position are measured based on the largest benefit that is more-likely-than-not to be realized upon ultimate settlement. Although the ultimate resolution of EGTS' federal, state and local income tax examinations is uncertain, EGTS believes it has made adequate provisions for these income tax positions. The aggregate amount of any additional income tax liabilities that may result from these examinations is not expected to have a material impact on EGTS' consolidated financial results. Refer to EGTS' Note 9 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding EGTS' income taxes.

It is probable that EGTS will pass income tax benefit and expense related to the federal tax rate change from 35% to 21%, certain property-related basis differences and other various differences on to their customers. As of December 31, 2024, these amounts were recognized as a net regulatory liability of \$371 million and will be included in regulated rates when the temporary differences reverse.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

EGTS' Consolidated Balance Sheets include assets and liabilities with fair values that are subject to market risks. EGTS' significant market risks are primarily associated with interest rates and the extension of credit to counterparties with which EGTS transacts. The following discussion addresses the significant market risks associated with EGTS' business activities. EGTS has established guidelines for credit risk management. Refer to Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding EGTS' contracts accounted for as derivatives.

Interest Rate Risk

EGTS is exposed to interest rate risk on its outstanding variable-rate short- and long-term debt and future debt issuances. EGTS manages its interest rate risk by limiting its exposure to variable interest rates primarily through the issuance of fixed-rate long-term debt and by monitoring market changes in interest rates. As a result of the fixed interest rates, EGTS' fixed-rate long-term debt does not expose EGTS to the risk of loss due to changes in market interest rates. Additionally, because fixed-rate long-term debt is not carried at fair value on the Consolidated Balance Sheets, changes in fair value would impact earnings and cash flows only if EGTS were to reacquire all or a portion of these instruments prior to their maturity. The nature and amount of EGTS' short- and long-term debt can be expected to vary from period to period as a result of future business requirements, market conditions and other factors. Refer to Note 8 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional discussion of EGTS' long-term debt.

As of December 31, 2024 and 2023, EGTS had short-term variable-rate obligations totaling \$— million and \$2 million that expose EGTS to the risk of increased interest expense in the event of increases in short-term interest rates. If variable interest rates were to increase by 10% from December 31 levels, it would not have a material effect on EGTS' annual interest expense. The carrying value of the variable-rate obligations approximates fair value as of December 31, 2024 and 2023.

Credit Risk

EGTS is exposed to counterparty credit risk associated with natural gas transmission and storage service contracts with utilities, natural gas producers, power generators, industrials, energy marketing companies, financial institutions and other market participants. Credit risk may be concentrated to the extent EGTS' counterparties have similar economic, industry or other characteristics and due to direct and indirect relationships among the counterparties. Before entering into a transaction, EGTS analyzes the financial condition of each wholesale counterparty, establishes limits on the amount of unsecured credit to be extended to each counterparty and evaluates the appropriateness of unsecured credit limits on an ongoing basis. To further mitigate counterparty credit risk, EGTS obtains third-party guarantees, letters of credit, financial guarantee bonds and cash deposits. If required, EGTS exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

EGTS' gross credit exposure for each counterparty is calculated as outstanding receivables plus any unrealized on- or off-balance sheet exposure, taking into account contractual netting rights. Gross credit exposure is calculated prior to the application of collateral. As of December 31, 2024, EGTS' credit exposure totaled \$46 million. Of this amount, investment grade counterparties, including those internally rated, represented 100%, with three investment grade counterparties representing 71% of the credit exposure.

Item 8. Financial Statements and Supplementary Data	
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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Eastern Gas Transmission and Storage, Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Eastern Gas Transmission and Storage, Inc., and subsidiaries ("EGTS") as of December 31, 2024 and 2023, the related consolidated statements of operations, comprehensive income, changes in shareholder's equity, and cash flows, for each of the three years in the period ended December 31, 2024, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of EGTS as of December 31, 2024 and 2023, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2024, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of EGTS' management. Our responsibility is to express an opinion on EGTS' financial statements 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 EGTS 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 financial statements are free of material misstatement, whether due to error or fraud. EGTS is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of EGTS' internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the 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 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 financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the executive committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the 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.

Regulatory Matters — Effects of Rate Regulation on the Financial Statements — Refer to Notes 2 and 6 to the Financial Statements

EGTS is subject to rate regulation by the Federal Energy Regulatory Commission (the "FERC"), which has jurisdiction with respect to the rates of interstate natural gas transmission companies in the respective service territories where EGTS operates. Management has determined its regulated operations meet the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the specialized rules to account for the effects of cost-based rate regulation. Accounting for the economic effects of rate regulation has a pervasive effect on the financial statements.

Revenue provided by the EGTS' interstate natural gas transmission operations is based primarily on rates approved by the FERC. EGTS defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in regulated rates occur. EGTS continually evaluates the applicability of the guidance for regulated operations and whether its regulatory assets and liabilities are probable of inclusion in future rates by considering factors such as a change in the regulator's approach to setting rates from cost-based ratemaking to another form of regulation, other regulatory actions or the impact of competition that could limit EGTS' ability to recover its costs. The evaluation reflects the current political and regulatory climate. If it becomes no longer probable that the deferred costs or income will be included in future regulated rates, the regulatory assets and liabilities will be recognized in net income, returned to customers, or re-established as accumulated other comprehensive income (loss).

We identified the effects of rate regulation on the financial statements as a critical audit matter due to the significant judgments made by management to support its assertions about affected account balances and disclosures and the high degree of subjectivity involved in assessing the impact of regulatory orders on the financial statements. Management judgments include assessing the likelihood of (1) recovery in future rates of incurred costs, (2) a disallowance of part of the cost of recently completed plant or plant under construction, and (3) a refund to customers. Given that management's accounting judgments are based on assumptions about the outcome of decisions by the FERC, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate setting process due to its inherent complexities.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the uncertainty of decisions by the FERC included the following, among others:

- We evaluated EGTS' disclosures related to the effects of rate regulation by testing recorded balances and evaluating regulatory developments.
- We read relevant regulatory orders issued by the FERC, regulatory statutes, filings made by EGTS and interveners, and other external information. We evaluated relevant external information and compared it to certain recorded regulatory asset and liability balances for completeness.
- For certain regulatory matters, we inspected EGTS' filings with the FERC, and the filings with the FERC by intervenors to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedents of the FERC's treatment of similar costs under similar circumstances.
- We inquired of management about property, plant, and equipment that may be abandoned. We inquired of management to identify projects that are designed to replace assets that may be retired prior to the end of the useful life. We inspected minutes of the board of directors and regulatory orders and other filings with the FERC to identify any evidence that may contradict management's assertion regarding probability of an abandonment.

/s/ Deloitte & Touche LLP

Richmond, Virginia
February 21, 2025

We have served as EGTS' auditor since 2000.

EASTERN GAS TRANSMISSION AND STORAGE, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Amounts in millions)

	As of December 31,	
	2024	2023
ASSETS		
Current assets:		
Cash and cash equivalents	\$ 8	\$ 5
Restricted cash and cash equivalents	24	29
Trade receivables, net	93	104
Receivables from affiliates	17	9
Inventories	55	59
Income taxes receivable	2	70
Prepayments and other deferred charges	28	22
Natural gas imbalances	72	34
Other current assets	8	5
Total current assets	307	337
Property, plant and equipment, net	4,771	4,715
Other assets	73	92
Total assets	\$ 5,151	\$ 5,144

The accompanying notes are an integral part of these consolidated financial statements.

EASTERN GAS TRANSMISSION AND STORAGE, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (continued)
(Amounts in millions, except share data)

	As of December 31,	
	2024	2023
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities:		
Accounts payable	\$ 55	\$ 41
Accounts payable to affiliates	27	29
Accrued property, income and other taxes	68	58
Accrued employee expenses	18	20
Notes payable to affiliates	—	2
Regulatory liabilities	13	22
Customer and security deposits	24	29
Current portion of long-term debt	—	111
Other current liabilities	25	28
Total current liabilities	230	340
Long-term debt	1,622	1,472
Regulatory liabilities	527	523
Other long-term liabilities	166	121
Total liabilities	2,545	2,456
Commitments and contingencies (Note 14)		
Shareholder's equity:		
Common stock - 75,000 shares authorized, \$10,000 par value, 60,101 issued and outstanding	609	609
Additional paid-in capital	1,352	1,304
Retained earnings	671	803
Accumulated other comprehensive loss, net	(26)	(28)
Total shareholder's equity	2,606	2,688
Total liabilities and shareholder's equity	\$ 5,151	\$ 5,144

The accompanying notes are an integral part of these consolidated financial statements.

EASTERN GAS TRANSMISSION AND STORAGE, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2024	2023	2022
Operating revenue	\$ 997	\$ 1,024	\$ 973
Operating expenses:			
Cost of (excess) gas	7	38	(33)
Operations and maintenance	384	404	364
Depreciation and amortization	155	151	152
Property and other taxes	53	50	54
Total operating expenses	599	643	537
Operating income	398	381	436
Other income (expense):			
Interest expense	(69)	(71)	(69)
Allowance for borrowed funds	2	1	1
Allowance for equity funds	7	5	4
Other, net	5	1	(2)
Total other income (expense)	(55)	(64)	(66)
Income (loss) before income tax expense (benefit)	343	317	370
Income tax expense (benefit)	87	79	109
Net income	\$ 256	\$ 238	\$ 261

The accompanying notes are an integral part of these consolidated financial statements.

EASTERN GAS TRANSMISSION AND STORAGE, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Amounts in millions)

	Years Ended December 31,		
	2024	2023	2022
Net income	\$ 256	\$ 238	\$ 261
Other comprehensive income, net of tax:			
Unrealized gains on cash flow hedges, net of tax of \$1, \$1 and \$1	2	2	1
Total other comprehensive income, net of tax	2	2	1
Comprehensive income	<u>\$ 258</u>	<u>\$ 240</u>	<u>\$ 262</u>

The accompanying notes are an integral part of these consolidated financial statements.

EASTERN GAS TRANSMISSION AND STORAGE, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY
(Amounts in millions, except shares)

	Common Stock		Additional	Retained	Accumulated	Total
	Shares	Amount	Paid-in	Earnings	Other	Shareholder's
			Capital		Comprehensive	Equity
					Loss, Net	
Balance, December 31, 2021	60,101	\$ 609	\$ 1,241	\$ 721	\$ (31)	\$ 2,540
Net income	—	—	—	261	—	261
Other comprehensive income	—	—	—	—	1	1
Dividends declared	—	—	—	(236)	—	(236)
Contributions	—	—	34	—	—	34
Balance, December 31, 2022	60,101	609	1,275	746	(30)	2,600
Net income	—	—	—	238	—	238
Other comprehensive income	—	—	—	—	2	2
Dividends declared	—	—	—	(181)	—	(181)
Contributions	—	—	29	—	—	29
Balance, December 31, 2023	60,101	609	1,304	803	(28)	2,688
Net income	—	—	—	256	—	256
Other comprehensive income	—	—	—	—	2	2
Dividends declared	—	—	—	(388)	—	(388)
Contributions	—	—	48	—	—	48
Balance, December 31, 2024	60,101	\$ 609	\$ 1,352	\$ 671	\$ (26)	\$ 2,606

The accompanying notes are an integral part of these consolidated financial statements.

EASTERN GAS TRANSMISSION AND STORAGE, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Amounts in millions)

	Years Ended December 31,		
	2024	2023	2022
Cash flows from operating activities:			
Net income	\$ 256	\$ 238	\$ 261
Adjustments to reconcile net income to net cash flows from operating activities:			
(Gains) losses on other items, net	(1)	(8)	1
Depreciation and amortization	155	151	152
Allowance for equity funds	(7)	(5)	(4)
Changes in regulatory assets and liabilities	(18)	(76)	61
Deferred income taxes	67	119	92
Other, net	(1)	(8)	6
Changes in other operating assets and liabilities:			
Trade receivables and other assets	39	15	(14)
Receivables from affiliates	(8)	4	(4)
Gas balancing activities	9	27	(31)
Accrued property, income and other taxes	(2)	(57)	18
Accounts payable to affiliates	(2)	24	(8)
Accounts payable and other liabilities	10	(6)	22
Net cash flows from operating activities	<u>497</u>	<u>418</u>	<u>552</u>
Cash flows from investing activities:			
Capital expenditures	(255)	(241)	(275)
Proceeds from assignment of shale development rights	—	8	—
Proceeds from sales of marketable securities	3	—	—
Notes to affiliates	(25)	—	(8)
Repayment of notes by affiliates	25	—	11
Other, net	1	(4)	(14)
Net cash flows from investing activities	<u>(251)</u>	<u>(237)</u>	<u>(286)</u>
Cash flows from financing activities:			
Proceeds from long-term debt	149	—	—
Repayments of long-term debt	(111)	—	—
Repayment of notes payable to affiliates, net	(2)	(34)	(32)
Proceeds from equity contributions	13	—	—
Dividends paid	(297)	(158)	(215)
Net cash flows from financing activities	<u>(248)</u>	<u>(192)</u>	<u>(247)</u>
Net change in cash and cash equivalents and restricted cash and cash equivalents	(2)	(11)	19
Cash and cash equivalents and restricted cash and cash equivalents at beginning of period	34	45	26
Cash and cash equivalents and restricted cash and cash equivalents at end of period	<u>\$ 32</u>	<u>\$ 34</u>	<u>\$ 45</u>

The accompanying notes are an integral part of these consolidated financial statements.

EASTERN GAS TRANSMISSION AND STORAGE, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Organization and Operations

Eastern Gas Transmission and Storage, Inc. and its subsidiaries ("EGTS") conduct business activities consisting of Federal Energy Regulatory Commission ("FERC")-regulated interstate natural gas transmission systems and underground storage. EGTS' operations include transmission assets located in Maryland, New York, Ohio, Pennsylvania, Virginia and West Virginia. EGTS also operates one of the nation's largest underground natural gas storage systems located in New York, Pennsylvania and West Virginia. EGTS is a wholly owned subsidiary of Eastern Energy Gas Holdings, LLC ("Eastern Energy Gas"), which is an indirect wholly owned subsidiary of Berkshire Hathaway Energy Company ("BHE"). BHE is a holding company based in Des Moines, Iowa that has investments in subsidiaries principally engaged in energy businesses. BHE is a wholly owned subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway").

(2) Summary of Significant Accounting Policies

Basis of Consolidation and Presentation

The Consolidated Financial Statements include the accounts of EGTS and its subsidiaries in which it holds a controlling financial interest as of the financial statement date. Intercompany accounts and transactions have been eliminated.

Use of Estimates in Preparation of Financial Statements

The preparation of the Consolidated Financial Statements in conformity with accounting principles generally accepted in the United States of America ("GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the period. These estimates include, but are not limited to, the effects of regulation; recovery of long-lived assets; certain assumptions made in accounting for pension and other postretirement benefits; asset retirement obligations ("AROs"); income taxes; unbilled revenue; valuation of certain financial assets and liabilities, including derivative contracts; and accounting for contingencies. Actual results may differ from the estimates used in preparing the Consolidated Financial Statements.

Accounting for the Effects of Certain Types of Regulation

EGTS prepares its Consolidated Financial Statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, EGTS defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in regulated rates occur.

If it becomes no longer probable that the deferred costs or income will be included in future regulated rates, the related regulatory assets and liabilities will be recognized in net income, returned to customers or re-established as accumulated other comprehensive income (loss) ("AOCI").

Fair Value Measurements

As defined under GAAP, fair value is the price that would be received to sell an asset or paid to transfer a liability between market participants in the principal market or in the most advantageous market when no principal market exists. Adjustments to transaction prices or quoted market prices may be required in illiquid or disorderly markets in order to estimate fair value. Alternative valuation techniques may be appropriate under the circumstances to determine the value that would be received to sell an asset or paid to transfer a liability in an orderly transaction. Market participants are assumed to be independent, knowledgeable, able and willing to transact an exchange and not under duress. Nonperformance or credit risk is considered when determining fair value. Considerable judgment may be required in interpreting market data used to develop the estimates of fair value. Accordingly, estimates of fair value presented herein are not necessarily indicative of the amounts that could be realized in a current or future market exchange.

Cash and Cash Equivalents and Restricted Cash and Cash Equivalents

Cash equivalents consist of funds invested in money market mutual funds, U.S. Treasury Bills and other investments with a maturity of three months or less when purchased. Cash and cash equivalents exclude amounts where availability is restricted by legal requirements, loan agreements or other contractual provisions. Restricted cash and cash equivalents consist of customer deposits as allowed under the FERC gas tariff. A reconciliation of cash and cash equivalents and restricted cash and cash equivalents as of December 31, 2024 and 2023, as presented on the Consolidated Statements of Cash Flows is outlined below and disaggregated by the line items in which they appear on the Consolidated Balance Sheets (in millions):

	As of December 31,	
	2024	2023
Cash and cash equivalents	\$ 8	\$ 5
Restricted cash and cash equivalents	24	29
Total cash and cash equivalents and restricted cash and cash equivalents	<u>\$ 32</u>	<u>\$ 34</u>

Investments

Trading securities are carried at fair value with realized and unrealized gains and losses recognized in earnings.

Allowance for Credit Losses

Trade receivables are primarily short-term in nature with stated collection terms of less than one year from the date of origination and are stated at the outstanding principal amount, net of an estimated allowance for credit losses. The allowance for credit losses is based on EGTS' assessment of the collectability of amounts owed to EGTS by its customers. This assessment requires judgment regarding the ability of customers to pay or the outcome of any pending disputes. In measuring the allowance for credit losses for trade receivables, EGTS primarily utilizes credit loss history. However, EGTS may adjust the allowance for credit losses to reflect current conditions and reasonable and supportable forecasts that deviate from historical experience. The changes in the balance of the allowance for credit losses, which is included in trade receivables, net on the Consolidated Balance Sheets, is summarized as follows for the years ended December 31, (in millions):

	2024	2023	2022
Beginning balance	\$ —	\$ —	\$ 3
Write-offs, net	—	—	(3)
Ending balance	<u>\$ —</u>	<u>\$ —</u>	<u>\$ —</u>

Derivatives

EGTS employs a number of different derivative contracts, which may include forwards, futures, options, swaps and other agreements, to manage its commodity price and interest rate risks. Derivative contracts are recorded on the Consolidated Balance Sheets as either assets or liabilities and are stated at estimated fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by GAAP. Derivative balances reflect offsetting permitted under master netting agreements with counterparties and cash collateral paid or received under such agreements. Cash collateral received from or paid to counterparties to secure derivative contract assets or liabilities in excess of amounts offset is included in other current assets or other current liabilities on the Consolidated Balance Sheets.

Commodity derivatives used in normal business operations that are settled by physical delivery, among other criteria, are eligible for and may be designated as normal purchases or normal sales. Normal purchases or normal sales contracts are not marked-to-market and settled amounts are recognized as operating revenue or cost of gas on the Consolidated Statements of Operations.

For EGTS' derivatives not designated as hedging contracts, unrealized gains and losses are recognized on the Consolidated Statements of Operations as operating revenue for derivatives related to natural gas sales contracts.

For EGTS' derivatives designated as hedging contracts, EGTS formally assesses, at inception and thereafter, whether the hedging contract is highly effective in offsetting changes in the hedged item. EGTS formally documents hedging activity by transaction type and risk management strategy. For derivative instruments that are accounted for as cash flow hedges or fair value hedges, the cash flows from the derivatives and from the related hedged items are classified in operating cash flows.

Changes in the estimated fair value of a derivative contract designated and qualified as a cash flow hedge, to the extent effective, are included on the Consolidated Statements of Changes in Equity as AOCI, net of tax, until the contract settles and the hedged item is recognized in earnings. EGTS discontinues hedge accounting prospectively when it has determined that a derivative contract no longer qualifies as an effective hedge, or when it is no longer probable that the hedged forecasted transaction will occur. When hedge accounting is discontinued because the derivative contract no longer qualifies as an effective hedge, future changes in the estimated fair value of the derivative contract are charged to earnings. Gains and losses related to discontinued hedges that were previously recorded in AOCI will remain in AOCI until the contract settles and the hedged item is recognized in earnings, unless it becomes probable that the hedged forecasted transaction will not occur at which time associated deferred amounts in AOCI are immediately recognized in earnings.

Inventories

Inventories consist mainly of materials and supplies and are determined using the average cost method.

Natural Gas Imbalances

Natural gas imbalances occur when the physical amount of natural gas delivered from, or received by, a pipeline system or storage facility differs from the contractual amount of natural gas delivered or received. EGTS values these imbalances due to, or from, shippers and operators at an appropriate index price at period end, subject to the terms of its tariff for regulated entities. Imbalances are primarily settled in-kind. Imbalances due to EGTS from other parties are reported in natural gas imbalances and imbalances that EGTS owes to other parties are reported in other current liabilities on the Consolidated Balance Sheets.

Property, Plant and Equipment, Net

General

Additions to property, plant and equipment are recorded at cost. EGTS capitalizes all construction-related materials, direct labor and contract services, as well as indirect construction costs. Indirect construction costs include debt and equity allowance for funds used during construction ("AFUDC"), as applicable. The cost of additions and betterments are capitalized, while costs incurred that do not improve or extend the useful lives of the related assets are generally expensed.

Depreciation and amortization are generally computed by applying the composite or straight-line method based on estimated useful lives. Depreciation studies are completed by EGTS to determine the appropriate group lives, net salvage and group depreciation rates. These studies are reviewed and rates are ultimately approved by the FERC. Net salvage includes the estimated future residual values of the assets and any estimated removal costs recovered through approved depreciation rates. Estimated removal costs are recorded as either a cost of removal regulatory liability or an ARO liability on the Consolidated Balance Sheets, depending on whether the obligation meets the requirements of an ARO. As actual removal costs are incurred, the associated liability is reduced.

Generally when EGTS retires or sells a component of regulated property, plant and equipment, it charges the original cost, net of any proceeds from the disposition, to accumulated depreciation. Any gain or loss on disposals of all other assets is recorded through earnings.

Debt and equity AFUDC, which represent the estimated costs of debt and equity funds necessary to finance the construction of regulated facilities, is capitalized by EGTS as a component of property, plant and equipment, with offsetting credits to the Consolidated Statements of Operations. AFUDC is computed based on guidelines set forth by the FERC. After construction is completed, EGTS is permitted to earn a return on these costs as a component of the related assets, as well as recover these costs through depreciation expense over the useful lives of the related assets.

Asset Retirement Obligations

EGTS recognizes AROs when it has a legal obligation to perform decommissioning, reclamation or removal activities upon retirement of an asset. EGTS' AROs are primarily related to the obligations associated with its interstate natural gas transmission and storage well assets. The fair value of an ARO liability is recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made, and is added to the carrying amount of the associated asset, which is then depreciated over the remaining useful life of the asset. Subsequent to the initial recognition, the ARO liability is adjusted for any revisions to the original estimate of undiscounted cash flows (with corresponding adjustments to property, plant and equipment, net) and for accretion of the ARO liability due to the passage of time. For EGTS, the difference between the ARO liability, the corresponding ARO asset included in property, plant and equipment, net and amounts recovered in rates to satisfy such liabilities is recorded as a regulatory asset or liability.

Impairment

EGTS evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or when the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value and any resulting impairment loss is reflected on the Consolidated Statements of Operations. As substantially all property, plant and equipment supports EGTS' regulated businesses, the impacts of regulation are considered when evaluating the carrying value of regulated assets.

Leases

EGTS has non-cancelable operating leases primarily for office space, office equipment and land. These leases generally require EGTS to pay for insurance, taxes and maintenance applicable to the leased property. Given the capital-intensive nature of the utility industry, it is common for a portion of lease costs to be capitalized when used during construction or maintenance of assets, in which the associated costs will be capitalized with the corresponding asset and depreciated over the remaining life of that asset. Certain leases contain renewal options for varying periods and escalation clauses for adjusting rent to reflect changes in price indices. EGTS does not include options in its lease calculations unless there is a triggering event indicating EGTS is reasonably certain to exercise the option. EGTS' accounting policy is to not recognize right-of-use assets and lease obligations for leases with contract terms of one year or less and not separate lease components from non-lease components and instead account for each separate lease component and the non-lease components associated with a lease as a single lease component. Leases will be evaluated for impairment in line with Accounting Standards Codification 360, "Property, Plant and Equipment" when a triggering event has occurred that might affect the value and use of the assets being leased.

EGTS' operating right-of-use assets are recorded in other assets and the operating lease liabilities are recorded in current and long-term other liabilities accordingly.

Revenue Recognition

EGTS uses a single five-step model to identify and recognize revenue from contracts with customers ("Customer Revenue") upon transfer of control of promised goods or services in an amount that reflects the consideration to which EGTS expects to be entitled in exchange for those goods or services. EGTS records sales and excise taxes collected directly from customers and remitted directly to the taxing authorities on a net basis on the Consolidated Statements of Operations.

A majority of EGTS' Customer Revenue is derived from tariff-based sales arrangements approved by the FERC. These tariff-based revenues are mainly comprised of natural gas transmission and storage services and have performance obligations which are satisfied over time as services are provided.

Revenue recognized is equal to what EGTS has the right to invoice as it corresponds directly with the value to the customer of EGTS' performance to date and includes billed and unbilled amounts. Trade receivables, net on the Consolidated Balance Sheets relate substantially to Customer Revenue, including unbilled revenue of \$17 million as of December 31, 2023. Payments for amounts billed are generally due from the customer within 30 days of billing. Rates charged for energy products and services are established by regulators or contractual arrangements that establish the transaction price as well as the allocation of price amongst the separate performance obligations. When preliminary regulated rates are permitted to be billed prior to final approval by the applicable regulator, certain revenue collected may be subject to refund and a liability for estimated refunds is accrued. In the event one of the parties to a contract has performed before the other, EGTS would recognize a contract asset or contract liability depending on the relationship between EGTS' performance and the customer's payment. EGTS has recognized contract assets of \$7 million and \$8 million as of December 31, 2024 and 2023, respectively, and \$3 million and \$2 million of contract liabilities as of December 31, 2024 and 2023, respectively, due to EGTS' performance on certain contracts.

Unamortized Debt Premiums, Discounts and Debt Issuance Costs

Premiums, discounts and debt issuance costs incurred for the issuance of long-term debt are amortized over the term of the related financing using the effective interest method.

Income Taxes

Berkshire Hathaway includes EGTS in its consolidated U.S. federal income tax return. Consistent with established regulatory practice, EGTS' provision for income taxes has been computed on a stand-alone basis.

Deferred income tax assets and liabilities are based on differences between the financial statement and income tax basis of assets and liabilities using enacted income tax rates expected to be in effect for the year in which the differences are expected to reverse. Changes in deferred income tax assets and liabilities associated with components of OCI are charged or credited directly to OCI. Changes in deferred income tax assets and liabilities associated with certain property-related basis differences and other various differences that EGTS' regulated businesses deems probable to be passed on to its customers are charged or credited directly to a regulatory asset or liability and will be included in regulated rates when the temporary differences reverse. Other changes in deferred income tax assets and liabilities are included as a component of income tax expense. Changes in deferred income tax assets and liabilities attributable to changes in enacted income tax rates are charged or credited to income tax expense or a regulatory asset or liability in the period of enactment. Valuation allowances are established when necessary to reduce deferred income tax assets to the amount that is more-likely-than-not to be realized.

EGTS recognizes the tax benefit from an uncertain tax position only if it is more-likely-than-not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the Consolidated Financial Statements from such a position are measured based on the largest benefit that is more-likely-than-not to be realized upon ultimate settlement. Estimated interest and penalties, if any, related to uncertain tax positions are included as a component of income tax expense (benefit) on the Consolidated Statements of Operations.

Segment Information

EGTS currently has one reportable segment, which includes its natural gas transmission and storage operations. EGTS' chief operating decision maker ("CODM") is the BHE Pipeline Group (which consists primarily of BHE GT&S, LLC, Northern Natural Gas Company and Kern River Gas Transmission Company) President and Chief Executive Officer. The CODM uses net income, as reported on the Consolidated Statements of Operations, and generally considers actual results versus historical results, budgets or forecast, as well as unique risks and opportunities, when making decisions about the allocation of resources and capital. The segment expenses regularly provided to the CODM align with the captions presented on the Consolidated Statements of Operations. The measure of segment assets is reported on the Consolidated Balance Sheets as total assets.

In November 2023, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2023-07, Segment Reporting Topic 280, "Segment Reporting—Improvements to Reportable Segment Disclosures" which allows disclosure of one or more measures of segment profit or loss used by the chief operating decision maker to allocate resources and assess performance. Additionally, the standard requires enhanced disclosures of significant segment expenses and other segment items as well as incremental qualitative disclosures on both an annual and interim basis. This guidance is effective for annual reporting periods beginning after December 15, 2023, and interim reporting periods after December 15, 2024. Early adoption is permitted and retrospective application is required for all periods presented. EGTS adopted this guidance for the fiscal year beginning January 1, 2024 under the retrospective method. The adoption did not have a material impact on EGTS' Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

In December 2023, the FASB issued ASU No. 2023-09, Income Taxes Topic 740, "Income Tax—Improvements to Income Tax Disclosures" which requires enhanced disclosures, including specific categories and disaggregation of information in the effective tax rate reconciliation, disaggregated information related to income taxes paid, income or loss from continuing operations before income tax expense or benefit, and income tax expense or benefit from continuing operations. This guidance is effective for annual reporting periods beginning after December 15, 2024. Early adoption is permitted and should be applied on a prospective basis, however retrospective application is permitted. EGTS is currently evaluating the impact of adopting this guidance on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

In November 2024, the FASB issued ASU No. 2024-03, Income Statement—Reporting Comprehensive Income—Expense Disaggregation Disclosures Subtopic 220-40, "Disaggregation of Income Statement Expenses" which addresses requests from investors for more detailed information about certain expenses and requires disclosure of the amounts of purchases of inventory, employee compensation, depreciation and intangible asset amortization included in each relevant expense caption presented on the income statement. This guidance is effective for annual reporting periods beginning after December 15, 2026 and interim reporting periods beginning after December 15, 2027. Early adoption is permitted and should be applied on a prospective basis, however retrospective application is permitted. EGTS is currently evaluating the impact of adopting this guidance on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

(3) Property, Plant and Equipment, Net

Property, plant and equipment, net consists of the following as of December 31 (in millions):

	Depreciable Life	2024	2023
Interstate natural gas transmission assets	47 - 51 years	\$ 5,093	\$ 5,011
Storage assets	47 - 51 years	1,803	1,751
Intangible plant and other assets	12 - 53 years	386	364
Plant in-service		7,282	7,126
Accumulated depreciation and amortization		(2,699)	(2,563)
		4,583	4,563
Construction work-in-progress		188	152
Property, plant and equipment, net		<u>\$ 4,771</u>	<u>\$ 4,715</u>

Assignment of Shale Development Rights

In June 2023, EGTS conveyed development rights to a natural gas producer for approximately 6,500 acres of Utica Shale and Point Pleasant Formation underneath one of its natural gas storage fields and received proceeds of \$8 million and an overriding royalty interest in gas produced from the acreage. This transaction resulted in an \$8 million (\$6 million after-tax) gain, included in operations and maintenance expense in its Consolidated Statements of Operations

(4) Jointly Owned Utility Facilities

Under joint facility ownership agreements with other utilities, EGTS, as a tenant in common, has undivided interests in jointly owned transmission and storage facilities. EGTS accounts for its proportionate share of each facility, and each joint owner has provided financing for its share of each facility. Operating costs of each facility are assigned to joint owners primarily based on their percentage of ownership. Operating costs and expenses on the Consolidated Statements of Operations include EGTS' share of the expenses of these facilities.

The amounts shown in the table below represent EGTS' share in each jointly owned facility included in property, plant and equipment, net as of December 31, 2024 (dollars in millions):

	EGTS' Share	Facility in Service	Accumulated Depreciation and Amortization	Construction Work-in- Progress
Ellisburg Pool	39 %	\$ 33	\$ 13	\$ 1
Ellisburg Station	50	29	9	5
Harrison	50	55	20	3
Leidy	50	148	51	4
Oakford	50	213	75	1
Total		<u>\$ 478</u>	<u>\$ 168</u>	<u>\$ 14</u>

(5) Leases

The following table summarizes EGTS' leases recorded on the Consolidated Balance Sheets as of December 31 (in millions):

	2024	2023
Right-of-use assets:		
Operating leases	\$ 17	\$ 18
Total right-of-use assets	<u>\$ 17</u>	<u>\$ 18</u>
Lease liabilities:		
Operating leases	\$ 16	\$ 17
Total lease liabilities	<u>\$ 16</u>	<u>\$ 17</u>

The following table summarizes EGTS' operating lease costs for the years ended December 31 (in millions):

	2024	2023	2022
Total operating lease costs	\$ 2	\$ 2	\$ 2
Weighted-average remaining operating lease term (years)	11.7	12.7	13.7
Weighted-average operating lease discount rate	4.3 %	4.3 %	4.3 %

The following table summarizes EGTS' supplemental cash flow information relating to leases for the years ended December 31 (in millions):

	2024	2023	2022
Cash paid for amounts included in the measurement of lease liabilities:			
Operating cash flows from operating leases	\$ 2	\$ 2	\$ 2

EGTS has the following remaining operating lease commitments as of December 31, 2024 (in millions):

2025	\$ 2
2026	2
2027	2
2028	2
2029	1
Thereafter	11
Total undiscounted lease payments	20
Less - amounts representing interest	(4)
Lease liabilities	<u>\$ 16</u>

(6) Regulatory Matters

Regulatory Assets

Regulatory assets represent costs that are expected to be recovered in future regulated rates. EGTS' regulatory assets reflected on the Consolidated Balance Sheets consist of the following as of December 31 (in millions):

	Weighted Average Remaining Life	2024	2023
Employee benefit plans ⁽¹⁾	10 years	\$ 23	\$ 32
Other	Various	8	4
Total regulatory assets		<u>\$ 31</u>	<u>\$ 36</u>
Reflected as:			
Other current assets		\$ 7	\$ 3
Other assets		24	33
Total regulatory assets		<u>\$ 31</u>	<u>\$ 36</u>

(1) Represents costs expected to be recovered through future rates generally over the expected remaining service period of plan participants.

EGTS had regulatory assets not earning a return on investment of \$31 million and \$36 million as of December 31, 2024 and 2023, respectively.

Regulatory Liabilities

Regulatory liabilities represent income to be recognized or amounts expected to be returned to customers in future periods. EGTS' regulatory liabilities reflected on the Consolidated Balance Sheets consist of the following as of December 31 (in millions):

	Weighted Average Remaining Life	2024	2023
Deferred income taxes ⁽¹⁾	Various	\$ 371	\$ 377
Other postretirement benefit costs ⁽²⁾	Various	129	124
Cost of removal ⁽³⁾	48 years	34	28
Other	Various	6	16
Total regulatory liabilities		\$ 540	\$ 545

Reflected as:

Current liabilities	\$ 13	\$ 22
Noncurrent liabilities	527	523
Total regulatory liabilities	\$ 540	\$ 545

- (1) Amounts primarily represent income tax liabilities related to the federal tax rate change from 35% to 21% that are probable to be passed on to customers, offset by income tax benefits related to certain property-related basis differences and other various differences that were previously passed on to customers and will be included in regulated rates when the temporary differences reverse.
- (2) Reflects a regulatory liability for the collection of postretirement benefit costs allowed in rates in excess of expense incurred.
- (3) Amounts represent estimated costs, as accrued through depreciation rates and exclusive of ARO liabilities, of removing regulated property, plant and equipment in accordance with accepted regulatory practices. Refer to Note 11 for more information.

(7) Investments and Restricted Cash and Cash Equivalents

Investments and restricted cash and cash equivalents consists of the following as of December 31 (in millions):

	2024	2023
Investments:		
Investment funds	\$ 18	\$ 19
Restricted cash and cash equivalents:		
Customer deposits	24	29
Total restricted cash and cash equivalents	24	29
Total investments and restricted cash and cash equivalents	\$ 42	\$ 48
Reflected as:		
Current assets	\$ 24	\$ 29
Other assets	18	19
Total investments and restricted cash and cash equivalents	\$ 42	\$ 48

(8) Long-term Debt

EGTS' long-term debt consists of the following, including unamortized premiums, discounts and debt issuance costs, as of December 31 (dollars in millions):

	<u>Par Value</u>	<u>2024</u>	<u>2023</u>
3.60% Senior Notes, due 2024	\$ —	\$ —	\$ 111
3.00% Senior Notes, due 2029	426	423	422
5.02% Senior Notes, due 2034	150	149	—
4.80% Senior Notes, due 2043	346	342	342
4.60% Senior Notes, due 2044	444	437	437
3.90% Senior Notes, due 2049	273	271	271
Total long-term debt	<u><u>\$ 1,639</u></u>	<u><u>\$ 1,622</u></u>	<u><u>\$ 1,583</u></u>
Reflected as:			
Current portion of long-term debt		\$ —	\$ 111
Long-term debt		1,622	1,472
Total long-term debt		<u><u>\$ 1,622</u></u>	<u><u>\$ 1,583</u></u>

Annual Payment on Long-Term Debt

The annual repayments of long-term debt for the years beginning January 1, 2025 and thereafter, are as follows (in millions):

2025	\$ —
2026	—
2027	—
2028	—
2029	426
2030 and thereafter	1,213
Total	1,639
Unamortized discounts and debt issuance costs	(17)
Total	<u><u>\$ 1,622</u></u>

AOCI

The following table presents selected information related to losses on interest rate cash flow hedges included in AOCI in EGTS' Consolidated Balance Sheets as of December 31, 2024 (in millions):

	<u>AOCI After-Tax</u>	<u>Amounts Expected to be Reclassified to Earnings During the Next 12 Months After-Tax</u>	<u>Maximum Term</u>
Interest rate	\$ (26)	\$ (2)	240 months

EGTS reclassified \$3 million, \$3 million and \$2 million from AOCI to interest expense for the years ended December 31, 2024, 2023 and 2022, respectively.

(9) Income Taxes

Income tax expense (benefit) consists of the following for the years ended December 31 (in millions):

	2024	2023	2022
Current:			
Federal	\$ 8	\$ (28)	\$ 5
State	12	(12)	12
	<u>20</u>	<u>(40)</u>	<u>17</u>
Deferred:			
Federal	58	91	64
State	9	28	28
	<u>67</u>	<u>119</u>	<u>92</u>
Total	<u>\$ 87</u>	<u>\$ 79</u>	<u>\$ 109</u>

A reconciliation of the federal statutory income tax rate to the effective income tax rate applicable to income (loss) before income tax expense (benefit) is as follows for the years ended December 31:

	2024	2023	2022
Federal statutory income tax rate	21 %	21 %	21 %
State income tax, net of federal income tax benefit	5	4	9
Other, net	(1)	—	(1)
Effective income tax rate	<u>25 %</u>	<u>25 %</u>	<u>29 %</u>

The net deferred income tax liability consists of the following as of December 31 (in millions):

	2024	2023
Deferred income tax assets:		
Federal and state carryforwards	\$ 10	\$ 5
Employee benefits	23	26
Intangibles and goodwill	240	252
Derivatives and hedges	9	10
Other	5	5
Total deferred income tax assets	<u>287</u>	<u>298</u>
Deferred income tax liabilities:		
Property-related items	(325)	(264)
Debt exchange	(47)	(50)
Total deferred income tax liabilities	<u>(372)</u>	<u>(314)</u>
Net deferred income tax liability ⁽¹⁾	<u>\$ (85)</u>	<u>\$ (16)</u>

(1) As of December 31, 2024, net deferred income tax liability is presented in other long-term liabilities in the Consolidated Balance Sheets. As of December 31, 2023, net federal deferred income tax liability is presented in other long-term liabilities and net state deferred income tax asset is presented in other assets in the Consolidated Balance Sheets.

As of December 31, 2024, EGTS' state tax carryforwards, entirely related to \$10 million of net operating losses, expire at various intervals between 2036 and indefinite.

The U.S. Internal Revenue Service has not closed or effectively settled an examination of EGTS' income tax returns for any tax years beginning on or after November 1, 2020. The statute of limitations for EGTS' states remains open for periods beginning on or after November 1, 2020. The closure of examinations, or the expiration of the statute of limitations, for state filings may not preclude the state from adjusting the state net operating loss carryforward utilized in a year for which the statute of limitations is not closed.

(10) Employee Benefit Plans

Defined Benefit Plans

EGTS is a participant in benefit plans sponsored by MidAmerican Energy Company ("MidAmerican Energy"), an affiliate. The MidAmerican Energy Company Retirement Plan includes a qualified pension plan that provides pension benefits for eligible employees. The MidAmerican Energy Company Welfare Benefit Plan provides certain postretirement health care and life insurance benefits for eligible retirees on behalf of EGTS. EGTS made \$7 million, \$7 million and \$12 million of contributions to the MidAmerican Energy Company Retirement Plan for the years ended December 31, 2024, 2023 and 2022, respectively. EGTS made \$2 million of contributions to the MidAmerican Energy Company Welfare Benefit Plan for the years ended December 31, 2024, 2023 and 2022. Contributions related to these plans are reflected as net periodic benefit cost in operations and maintenance expense in the Consolidated Statements of Operations. Amounts attributable to EGTS were allocated from MidAmerican Energy in accordance with the intercompany administrative service agreement. Offsetting regulatory assets and liabilities have been recorded related to the amounts not yet recognized as a component of net periodic benefit costs that will be included in regulated rates.

Defined Contribution Plan

EGTS participates in the MidAmerican Energy defined contribution plan. EGTS' matching contributions are based on each participant's level of contribution. Contributions cannot exceed the maximum allowable for tax purposes. Beginning April 1, 2023, certain participants receive enhanced benefits in the plan and no longer accrue benefits in the noncontributory defined benefit pension plans. EGTS' contributions to the plans were \$10 million, \$9 million and \$5 million for the years ended December 31, 2024, 2023 and 2022, respectively.

(11) Asset Retirement Obligations

EGTS estimates its ARO liabilities based upon detailed engineering calculations of the amount and timing of the future cash spending for a third party to perform the required work. Spending estimates are escalated for inflation and then discounted at a credit-adjusted, risk-free rate. Changes in estimates could occur for a number of reasons, including changes in laws and regulations, plan revisions, inflation and changes in the amount and timing of the expected work.

EGTS does not recognize liabilities for AROs for which the fair value cannot be reasonably estimated. Due to the indeterminate removal date, the fair value of the interim removal of natural gas pipelines and certain storage wells in EGTS' underground natural gas storage network cannot currently be estimated, and no amounts are recognized on the Consolidated Financial Statements other than those included in the cost of removal regulatory liability established via approved depreciation rates in accordance with accepted regulatory practices. These accruals totaled \$34 million and \$28 million as of December 31, 2024 and 2023, respectively.

The following table reconciles the beginning and ending balances of EGTS' ARO liabilities for the years ended December 31 (in millions):

	2024	2023
Beginning balance	\$ 30	\$ 48
Retirements	(3)	(19)
Accretion	1	1
Ending balance	<u>\$ 28</u>	<u>\$ 30</u>
Reflected as:		
Current liabilities	\$ 3	\$ 5
Other long-term liabilities	25	25
Total ARO liability	<u>\$ 28</u>	<u>\$ 30</u>

(12) Risk Management and Hedging Activities

EGTS is exposed to the impact of market fluctuations in commodity prices, principally, to natural gas market fluctuations primarily related to fuel retained and used during the operation of the pipeline system. EGTS has established a risk management process that is designed to identify, assess, manage, mitigate, monitor and report, each of the various types of risk involved in its business. To mitigate a portion of its commodity price risk, EGTS uses commodity derivative contracts, which may include forwards, futures, options, swaps and other agreements, to effectively secure future supply or sell future production generally at fixed prices. EGTS does not hedge all of its commodity price risk, thereby exposing the unhedged portion to changes in market prices. See Note 13 for further information about fair value measurements and associated valuation methods for derivatives.

There have been no significant changes in EGTS' accounting policies related to derivatives. Refer to Notes 2 and 13 for additional information on derivative contracts.

Credit Risk

EGTS is exposed to counterparty credit risk associated with wholesale energy supply and marketing activities with other utilities, energy marketing companies, financial institutions and other market participants. Credit risk may be concentrated to the extent EGTS' counterparties have similar economic, industry or other characteristics and due to direct or indirect relationships among the counterparties. For the year ended December 31, 2024, the 10 largest customers provided 41% of the total storage and transmission revenues. Before entering into a transaction, EGTS analyzes the financial condition of each significant wholesale counterparty, establishes limits on the amount of unsecured credit to be extended to each counterparty and evaluates the appropriateness of unsecured credit limits on an ongoing basis. To further mitigate wholesale counterparty credit risk, EGTS enters into netting and collateral arrangements that may include margining and cross-product netting agreements and obtains third-party guarantees, letters of credit and cash deposits. If required, EGTS exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

(13) Fair Value Measurements

The carrying value of EGTS' cash, certain cash equivalents, receivables, payables, accrued liabilities and short-term borrowings approximates fair value because of the short-term maturity of these instruments. EGTS has various financial assets and liabilities that are measured at fair value on the Consolidated Financial Statements using inputs from the three levels of the fair value hierarchy. A financial asset or liability classification within the hierarchy is determined based on the lowest level input that is significant to the fair value measurement. The three levels are as follows:

- Level 1 - Inputs are unadjusted quoted prices in active markets for identical assets or liabilities that EGTS has the ability to access at the measurement date.
- Level 2 - Inputs include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived principally from or corroborated by observable market data by correlation or other means (market corroborated inputs).

- Level 3 - Unobservable inputs reflect EGTS' judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. EGTS develops these inputs based on the best information available, including its own data.

The following table presents EGTS' financial assets and liabilities recognized on the Consolidated Balance Sheets and measured at fair value on a recurring basis (in millions):

	Input Levels for Fair Value Measurements				
	Level 1	Level 2	Level 3	Total	
As of December 31, 2024					
Assets:					
Money market mutual funds	\$ 8	\$ —	\$ —	\$ 8	
Equity securities:					
Investment funds	18	—	—	18	
	<u>\$ 26</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 26</u>	
As of December 31, 2023					
Assets:					
Money market mutual funds	\$ 5	\$ —	\$ —	\$ 5	
Equity securities:					
Investment funds	19	—	—	19	
	<u>\$ 24</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 24</u>	

EGTS' investments in money market mutual funds and investment funds are stated at fair value. When available, a readily observable quoted market price or net asset value of an identical security in an active market is used to record the fair value.

Derivative contracts are recorded on the Consolidated Balance Sheets as either assets or liabilities and are stated at estimated fair value unless they are designated as normal purchase or normal sales and qualify for the exception afforded by GAAP. When available, the fair value of derivative contracts is estimated using unadjusted quoted prices for identical contracts in the market in which EGTS transacts. When quoted prices for identical contracts are not available, EGTS uses forward price curves. Forward price curves represent EGTS' estimates of the prices at which a buyer or seller could contract today for delivery or settlement at future dates. EGTS bases its forward price curves upon market price quotations, when available, or internally developed and commercial models, with internal and external fundamental data inputs. Market price quotations are obtained from independent brokers, exchanges, direct communication with market participants and actual transactions executed by EGTS. Market price quotations are generally readily obtainable for the applicable term of EGTS' outstanding derivative contracts; therefore, EGTS' forward price curves reflect observable market quotes. Market price quotations for certain natural gas trading hubs are not as readily obtainable due to the length of the contracts. Given that limited market data exists for these contracts, as well as for those contracts that are not actively traded, EGTS uses forward price curves derived from internal models based on perceived pricing relationships to major trading hubs that are based on unobservable inputs. The estimated fair value of these derivative contracts is a function of underlying forward commodity prices, related volatility, counterparty creditworthiness and duration of contracts.

EGTS' long-term debt is carried at cost, including unamortized premiums, discounts and debt issuance costs as applicable, on the Consolidated Financial Statements. The fair value of EGTS' long-term debt is a Level 2 fair value measurement and has been estimated based upon quoted market prices, where available, or at the present value of future cash flows discounted at rates consistent with comparable maturities with similar credit risks. The following table presents the carrying value and estimated fair value of EGTS' long-term debt as of December 31 (in millions):

	2024		2023	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	<u>\$ 1,622</u>	<u>\$ 1,409</u>	<u>\$ 1,583</u>	<u>\$ 1,386</u>

(14) Commitments and Contingencies

Environmental Laws and Regulations

EGTS is subject to federal, state and local laws and regulations regarding air quality, climate change, emissions performance standards, water quality and other environmental matters that have the potential to impact its current and future operations. EGTS believes it is in material compliance with all applicable laws and regulations.

Legal Matters

EGTS is party to a variety of legal actions arising out of the normal course of business. EGTS does not believe that such normal and routine litigation will have a material impact on its consolidated financial results.

Surety Bonds

As of December 31, 2024, EGTS had purchased \$15 million of surety bonds. Under the terms of the surety bonds, Eastern Energy Gas is obligated to indemnify the respective surety bond company for any amounts paid.

(15) Revenue from Contracts with Customers

The following table summarizes EGTS' Customer Revenue by regulated and other, with further disaggregation of regulated by line of business, for the years ended December 31 (in millions):

	2024	2023	2022
Customer Revenue:			
Regulated:			
Gas transmission	\$ 650	\$ 656	\$ 644
Gas storage	279	274	248
Wholesale	7	22	8
Other	1	2	—
Total regulated	937	954	900
Management services and other revenues	56	66	79
Total Customer Revenue	993	1,020	979
Other revenue ⁽¹⁾	4	4	(6)
Total operating revenue	\$ 997	\$ 1,024	\$ 973

- (1) Other revenue consists primarily of revenue recognized in accordance with Accounting Standards Codification ("ASC") 815, "Derivative and Hedging" which includes unrealized gains and losses for derivatives not designated as hedges related to natural gas sales contracts, contingent fees from certain farmout agreements recognized in accordance with ASC 450, "Contingencies" and the royalties from the conveyance of mineral rights accounted for under ASC 932 "Extractive Activities – Oil and Gas".

Remaining Performance Obligations

The following table summarizes EGTS' revenue it expects to recognize in future periods related to significant unsatisfied remaining performance obligations for fixed contracts with expected durations in excess of one year as of December 31, 2024 (in millions):

	Performance obligations expected to be satisfied		
	Less than 12 months	More than 12 months	Total
EGTS	\$ 787	\$ 2,997	\$ 3,784

(16) Supplemental Cash Flow Disclosures

The summary of supplemental cash flow disclosures as of and for the years ended December 31 is as follows (in millions):

	2024	2023	2022
Supplemental disclosure of cash flow information:			
Interest paid, net of amounts capitalized	\$ 66	\$ 69	\$ 67
Income taxes paid, net	\$ —	\$ 5	\$ 2
Supplemental disclosure of non-cash investing and financing transactions:			
Accruals related to property, plant and equipment additions	\$ 7	\$ 9	\$ 15
Equity dividends ⁽¹⁾	\$ (91)	\$ (23)	\$ (21)
Equity contributions	\$ 35	\$ 29	\$ 34

(1) Equity dividends represents the forgiveness of affiliated receivables.

(17) Related Party Transactions

EGTS is party to a tax-sharing agreement and is part of the Berkshire Hathaway consolidated U.S. federal income tax return. For current federal and state income taxes, EGTS had a payable to BHE of \$7 million as of December 31, 2024 and a receivable from BHE of \$57 million as of December 31, 2023.

As of December 31, 2023, EGTS had \$2 million of natural gas imbalances receivable from affiliates, presented in natural gas imbalances on the Consolidated Balance Sheets.

EGTS participates in certain MidAmerican Energy benefit plans as described in Note 10. As of December 31, 2024 and 2023, EGTS' amount due to MidAmerican Energy associated with these plans and reflected in other long-term liabilities on the Consolidated Balance Sheets was \$35 million and \$48 million, respectively.

Presented below are EGTS' significant transactions with related parties for the years ended December 31 (in millions):

	2024	2023	2022
Sales of natural gas and transmission and storage services	\$ 4	\$ 4	\$ 26
Purchases of natural gas and transmission and storage services	—	—	4
Services provided by related parties ⁽¹⁾	37	58	46
Services provided to related parties	52	59	62

(1) Includes capitalized expenditures.

Borrowings With Eastern Energy Gas

EGTS has a \$400 million intercompany revolving credit agreement from its parent, Eastern Energy Gas, expiring in March 2026. The credit agreement, which is for general corporate purposes, has a variable interest rate based on the Secured Overnight Financing Rate ("SOFR") plus a fixed spread. Net outstanding borrowings totaled \$2 million with a weighted-average interest rate of 5.41% as of December 31, 2023. There were no amounts outstanding under the credit agreement as of December 31, 2024. Interest expense related to the credit agreement totaled \$1 million for the year ended December 31, 2023.

Eastern Energy Gas has a \$400 million intercompany revolving credit agreement from EGTS expiring in March 2026. The credit agreement has a variable interest rate based on SOFR plus a fixed spread. There were no amounts outstanding under the credit agreement as of December 31, 2024 and 2023.

Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures*Disclosure Controls and Procedures*

At the end of the period covered by this Annual Report on Form 10-K, each of Berkshire Hathaway Energy Company, PacifiCorp, MidAmerican Funding, LLC, MidAmerican Energy Company, Nevada Power Company, Sierra Pacific Power Company, Eastern Energy Gas Holdings, LLC and Eastern Gas Transmission and Storage, Inc. carried out separate evaluations, under the supervision and with the participation of each such entity's management, including its Chief Executive Officer (principal executive officer) and its Chief Financial Officer (principal financial officer), or persons performing similar functions, of the effectiveness of the design and operation of its disclosure controls and procedures (as defined in Rule 13a-15(e) promulgated under the Securities and Exchange Act of 1934, as amended). Based upon these evaluations, management of each such entity, including its Chief Executive Officer (principal executive officer) and its Chief Financial Officer (principal financial officer), or persons performing similar functions, in each case, concluded that the disclosure controls and procedures for such entity were effective to ensure that information required to be disclosed by such entity 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 U.S. Securities and Exchange Commission's rules and forms, and is accumulated and communicated to its management, including its Chief Executive Officer (principal executive officer) and its Chief Financial Officer (principal financial officer), or persons performing similar functions, in each case, as appropriate to allow timely decisions regarding required disclosure by it. Each such entity hereby states that there has been no change in its internal control over financial reporting during the quarter ended December 31, 2024 that has materially affected, or is reasonably likely to materially affect, its internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting

Management of each of Berkshire Hathaway Energy Company, PacifiCorp, MidAmerican Funding, LLC, MidAmerican Energy Company, Nevada Power Company, Sierra Pacific Power Company, Eastern Energy Gas Holdings, LLC and Eastern Gas Transmission and Storage, Inc., respectively, is responsible for establishing and maintaining, for such entity, adequate internal control over financial reporting, as such term is defined in the Securities Exchange Act of 1934 Rule 13a-15(f). Under the supervision and with the participation of management for each such entity, including its Chief Executive Officer (principal executive officer) and its Chief Financial Officer (principal financial officer), or persons performing similar functions, in each case, such management conducted an evaluation for the relevant entity of the effectiveness of internal control over financial reporting as of December 31, 2024, as required by the Securities Exchange Act of 1934 Rule 13a-15(c). In making this assessment, management for each such respective entity used the criteria set forth in the framework in "Internal Control - Integrated Framework (2013)" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the evaluation conducted under the framework in "Internal Control - Integrated Framework (2013)," management for each such respective entity concluded that internal control over financial reporting for such entity was effective as of December 31, 2024.

Berkshire Hathaway Energy Company February 21, 2025	PacifiCorp February 21, 2025	MidAmerican Funding, LLC February 21, 2025
MidAmerican Energy Company February 21, 2025	Nevada Power Company February 21, 2025	Sierra Pacific Power Company February 21, 2025
Eastern Energy Gas Holdings, LLC February 21, 2025	Eastern Gas Transmission and Storage, Inc. February 21, 2025	

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

BERKSHIRE HATHAWAY ENERGY, PACIFICORP, MIDAMERICAN FUNDING, MIDAMERICAN ENERGY, NEVADA POWER, SIERRA PACIFIC, EASTERN ENERGY GAS AND EGTS

Information required by Item 10 is omitted pursuant to General Instruction I(2)(c) to Form 10-K.

Item 11. Executive Compensation

BERKSHIRE HATHAWAY ENERGY, PACIFICORP, MIDAMERICAN FUNDING, MIDAMERICAN ENERGY, NEVADA POWER, SIERRA PACIFIC, EASTERN ENERGY GAS AND EGTS

Information required by Item 11 is omitted pursuant to General Instruction I(2)(c) to Form 10-K.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

BERKSHIRE HATHAWAY ENERGY, PACIFICORP, MIDAMERICAN FUNDING, MIDAMERICAN ENERGY, NEVADA POWER, SIERRA PACIFIC, EASTERN ENERGY GAS AND EGTS

Information required by Item 12 is omitted pursuant to General Instruction I(2)(c) to Form 10-K.

Item 13. Certain Relationships and Related Transactions, and Director Independence

BERKSHIRE HATHAWAY ENERGY, PACIFICORP, MIDAMERICAN FUNDING, MIDAMERICAN ENERGY, NEVADA POWER, SIERRA PACIFIC, EASTERN ENERGY GAS AND EGTS

Information required by Item 13 is omitted pursuant to General Instruction I(2)(c) to Form 10-K.

Item 14. Principal Accountant Fees and Services

The following table shows the fees paid or accrued by each Registrant for audit and audit-related services and fees paid for tax and all other services rendered by Deloitte & Touche LLP (PCAOB ID No. 34), the member firms of Deloitte Touche Tohmatsu Limited, and their respective affiliates (collectively, the "Deloitte Entities") for each of the last two years (in millions):

	Berkshire Hathaway Energy ⁽¹⁾		PacifiCorp	MidAmerican Funding ⁽¹⁾	MidAmerican Energy	Nevada Power	Sierra Pacific	Eastern Energy Gas ⁽¹⁾	EGTS							
2024																
Audit fees ⁽²⁾	\$	13.0	\$	2.3	\$	1.5	\$	1.3	\$	1.0	\$	1.6	\$	0.9		
Audit-related fees ⁽³⁾		0.8		—		0.1		0.1		—		—		0.2	0.1	
Tax fees ⁽⁴⁾		0.1		—		—		—		—		—		—	—	
Other		0.5		—		—		—		—		—		—	—	
Total	\$	14.4	\$	2.3	\$	1.6	\$	1.4	\$	1.0	\$	1.0	\$	1.8	\$	1.0
2023																
Audit fees ⁽²⁾	\$	14.2	\$	1.9	\$	1.5	\$	1.4	\$	1.1	\$	1.1	\$	1.7	\$	1.0
Audit-related fees ⁽³⁾		0.8		—		—		—		—		—		0.2		0.1
Tax fees ⁽⁴⁾		—		—		—		—		—		—		—		—
Other		0.9		—		—		—		—		—		—		—
Total	\$	15.9	\$	1.9	\$	1.5	\$	1.4	\$	1.1	\$	1.1	\$	1.9	\$	1.1

- (1) The reported fees for Berkshire Hathaway Energy include those fees reported for PacifiCorp, MidAmerican Funding, Nevada Power, Sierra Pacific and Eastern Energy Gas while the reported fees for MidAmerican Funding include those fees reported for MidAmerican Energy and the reported fees for Eastern Energy Gas include those fees reported for EGTS.
- (2) Audit fees include fees for the audit of the consolidated financial statements and interim reviews of the quarterly financial statements for each Registrant, audit services provided in connection with required statutory audits of certain of BHE's subsidiaries and comfort letters, consents and other services related to SEC matters for each Registrant.
- (3) Audit-related fees primarily include fees for assurance and related services for any other statutory or regulatory requirements, audits of certain employee benefit plans and consultations on various accounting and reporting matters.
- (4) Tax fees include fees for services relating to tax compliance, tax planning and tax advice. These services include assistance regarding federal, state and international tax compliance, tax return preparation and tax audits.

The audit committee has considered whether the non-audit services provided to the Registrants by the Deloitte Entities impaired the independence of the Deloitte Entities and concluded that they did not. All of the services performed by the Deloitte Entities were pre-approved in accordance with the pre-approval policy adopted by the audit committee. The policy provides guidelines for the audit, audit-related, tax and other non-audit services that may be provided by the Deloitte Entities to the Registrants. The policy (a) identifies the guiding principles that must be considered by the audit committee in approving services to ensure that the Deloitte Entities' independence is not impaired; (b) describes the audit, audit-related and tax services that may be provided and the non-audit services that are prohibited; and (c) sets forth pre-approval requirements for all permitted services.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) Financial Statements and Schedules

(1) Financial Statements

The financial statements of all Registrants are included in their respective Item 8 of this Form 10-K. [108](#)

(2) Financial Statement Schedules

[BHE Parent Company Only Condensed Financial Statements \(Schedule I\)](#) [501](#)

[MidAmerican Funding, LLC Parent Company Only Condensed Financial Statements \(Schedule I\)](#) [506](#)

Schedules not listed above have been omitted because they are either not applicable, not required or the information required to be set forth therein is included on the Consolidated Financial Statements or notes thereto.

(3) [Management contracts or compensatory plans are identified by an asterisk in the Exhibit Index filed as part of this Annual Report.](#) [509](#)

(b) Exhibits

[The exhibits listed on the accompanying Exhibit Index are filed as part of this Annual Report.](#) [509](#)

Item 16. Form 10-K Summary

None.

BERKSHIRE HATHAWAY ENERGY COMPANY
PARENT COMPANY ONLY
CONDENSED BALANCE SHEETS
(Amounts in millions, except share amounts)

	As of December 31,	
	2024	2023
ASSETS		
Current assets:		
Cash and cash equivalents	\$ 78	\$ 166
Accounts receivable	—	—
Accounts receivable - affiliate	1,415	861
Notes receivable - affiliate	13	19
Income tax receivable	1	44
Other current assets	7	15
Total current assets	1,514	1,105
Investments in subsidiaries	60,499	61,032
Other investments	277	248
Goodwill	1,221	1,221
Other assets	1,280	1,291
Total assets	\$ 64,791	\$ 64,897
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable and other current liabilities	\$ 560	\$ 613
Notes payable - affiliate	502	202
Short-term debt	180	1,935
Current portion of BHE senior debt	1,650	—
Total current liabilities	2,892	2,750
BHE senior debt	11,457	13,101
BHE junior subordinated debentures	—	100
Notes payable - affiliate	—	—
Other long-term liabilities	433	512
Total liabilities	14,782	16,463
Equity:		
Preferred stock - 100,000,000 shares authorized, \$0.01 par value, 481,000 and — shares issued and outstanding	481	—
Common stock - 100 and 115,000,000 shares authorized, no par value, 1 and 75,627,913 shares issued and outstanding	—	—
Additional paid-in capital	5,558	5,573
Retained earnings	46,311	44,765
Accumulated other comprehensive loss, net	(2,341)	(1,904)
Total equity	50,009	48,434
Total liabilities and equity	\$ 64,791	\$ 64,897

The accompanying notes are an integral part of this financial statement schedule.

BERKSHIRE HATHAWAY ENERGY COMPANY
PARENT COMPANY ONLY
CONDENSED STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2024	2023	2022
Operating expenses:			
General and administration	\$ 79	\$ 77	\$ 31
Depreciation and amortization	7	7	8
Total operating expenses	86	84	39
Operating loss	(86)	(84)	(39)
Other income (expense):			
Interest expense	(669)	(702)	(629)
Other, net	57	49	(45)
Total other income (expense)	(612)	(653)	(674)
Loss before income tax expense (benefit) and equity income (loss)	(698)	(737)	(713)
Income tax expense (benefit)	(229)	(233)	(259)
Equity income (loss)	4,769	3,524	3,175
Net income attributable to BHE shareholders	4,300	3,020	2,721
Preferred dividends	—	34	46
Earnings on common shares	<u>\$ 4,300</u>	<u>\$ 2,986</u>	<u>\$ 2,675</u>

The accompanying notes are an integral part of this financial statement schedule.

BERKSHIRE HATHAWAY ENERGY COMPANY
PARENT COMPANY ONLY
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME
(Amounts in millions)

	Years Ended December 31,		
	2024	2023	2022
Net income	\$ 4,300	\$ 3,020	\$ 2,721
Other comprehensive (loss) income, net of tax	(437)	246	(809)
Comprehensive income attributable to BHE shareholders	<u>\$ 3,863</u>	<u>\$ 3,266</u>	<u>\$ 1,912</u>

The accompanying notes are an integral part of this financial statement schedule.

BERKSHIRE HATHAWAY ENERGY COMPANY
PARENT COMPANY ONLY
CONDENSED STATEMENTS OF CASH FLOWS
(In millions)

	Years Ended December 31,		
	2024	2023	2022
Cash flows from operating activities	<u>\$ 5,375</u>	<u>\$ 5,824</u>	<u>\$ 1,252</u>
Cash flows from investing activities:			
Investments in subsidiaries	(1,053)	(4,995)	(1,085)
Purchases of marketable securities	(10)	(39)	(20)
Proceeds from sales of marketable securities	13	35	11
Proceeds from other investments	—	—	—
Notes receivable from affiliate, net	6	(571)	390
Other, net	4	(18)	(44)
Net cash flows from investing activities	<u>(1,040)</u>	<u>(5,588)</u>	<u>(748)</u>
Cash flows from financing activities:			
Preferred stock redemptions	—	(850)	(800)
Preferred dividends	—	(38)	(50)
Common stock purchases	(2,276)	—	(870)
Proceeds from BHE senior debt	—	—	986
Repayments of BHE senior debt	—	(900)	—
Repayments of BHE subordinated debt	(91)	—	—
Net proceeds from (repayments of) short-term debt	(1,755)	1,690	245
Notes payable to affiliate, net	300	—	—
Notes payable	(600)	—	—
Other, net	(1)	(4)	(1)
Net cash flows from financing activities	<u>(4,423)</u>	<u>(102)</u>	<u>(490)</u>
Net change in cash and cash equivalents	<u>(88)</u>	<u>134</u>	<u>14</u>
Cash and cash equivalents at beginning of year	<u>166</u>	<u>32</u>	<u>18</u>
Cash and cash equivalents at end of year	<u><u>\$ 78</u></u>	<u><u>\$ 166</u></u>	<u><u>\$ 32</u></u>

The accompanying notes are an integral part of this financial statement schedule.

**BERKSHIRE HATHAWAY ENERGY COMPANY
PARENT COMPANY ONLY
NOTES TO CONDENSED FINANCIAL STATEMENTS**

Basis of Presentation - The condensed financial information of BHE investments in subsidiaries are presented under the equity method of accounting. Under this method, the assets and liabilities of subsidiaries are not consolidated. The investments in subsidiaries are recorded in the Condensed Balance Sheets. The income from operations of subsidiaries is reported on a net basis as equity income in the Condensed Statements of Operations.

Dividends and distributions from subsidiaries - Cash dividends paid to BHE by its subsidiaries for the years ended December 31, 2024, 2023 and 2022 were \$6.8 billion, \$6.8 billion and \$1.9 billion, respectively. In January and February 2025, BHE received cash dividends from its subsidiaries totaling \$65 million.

Guarantees and commitments - BHE has issued guarantees and letters of credit in respect of subsidiaries, equity method investments and other related parties aggregating \$3.5 billion and commitments.

See the notes to the consolidated BHE financial statements in Part II, Item 8 for other disclosures regarding long-term obligations (Notes 9, 10 and 11) and shareholders' equity (Note 18).

MIDAMERICAN FUNDING, LLC
PARENT COMPANY ONLY
CONDENSED BALANCE SHEETS
(Amounts in millions)

	As of December 31,	
	2024	2023
ASSETS		
Current assets:		
Receivables from affiliates	\$ —	\$ 1
Investments in and advances to subsidiaries	11,504	10,925
Total assets	\$ 11,504	\$ 10,926
LIABILITIES AND MEMBER'S EQUITY		
Current liabilities:		
Interest accrued and other current liabilities	\$ 6	\$ 5
Payable to affiliate	59	48
Long-term debt	240	240
Total liabilities	305	293
Member's equity:		
Paid-in capital	1,679	1,679
Retained earnings	9,520	8,954
Total member's equity	11,199	10,633
Total liabilities and member's equity	\$ 11,504	\$ 10,926

The accompanying notes are an integral part of this financial statement schedule.

MIDAMERICAN FUNDING, LLC
PARENT COMPANY ONLY
CONDENSED STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2024	2023	2022
Other income (expense):			
Interest expense	\$ (17)	\$ (17)	\$ (17)
Loss before income tax expense (benefit)	(17)	(17)	(17)
Income tax expense (benefit)	(5)	(5)	(5)
Equity in undistributed earnings of subsidiaries	1,003	992	959
Net income	<u>\$ 991</u>	<u>\$ 980</u>	<u>\$ 947</u>

The accompanying notes are an integral part of this financial statement schedule.

MIDAMERICAN FUNDING, LLC
PARENT COMPANY ONLY
CONDENSED STATEMENTS OF CASH FLOWS
(In millions)

	Years Ended December 31,		
	2024	2023	2022
Net cash flows from operating activities	<u>\$ (11)</u>	<u>\$ (12)</u>	<u>\$ (12)</u>
Net cash flows from investing activities:			
Dividends from subsidiary	425	1,025	69
Net cash flows from investing activities	<u>425</u>	<u>1,025</u>	<u>69</u>
Net cash flows from financing activities:			
Distributions to member	(425)	(1,025)	(69)
Net change in amounts payable to subsidiary	11	12	12
Net cash flows from financing activities	<u>(414)</u>	<u>(1,013)</u>	<u>(57)</u>
Net change in cash and cash equivalents	<u>—</u>	<u>—</u>	<u>—</u>
Cash and cash equivalents at beginning of year	<u>—</u>	<u>—</u>	<u>—</u>
Cash and cash equivalents at end of year	<u><u>\$ —</u></u>	<u><u>\$ —</u></u>	<u><u>\$ —</u></u>

The accompanying notes are an integral part of this financial statement schedule.

MIDAMERICAN FUNDING, LLC
PARENT COMPANY ONLY
NOTES TO CONDENSED FINANCIAL STATEMENTS

Incorporated by reference are MidAmerican Funding, LLC and Subsidiaries Consolidated Statements of Changes in Member's Equity for the three years ended December 31, 2024, 2023 and 2022 in Part II, Item 8.

Basis of Presentation - The condensed financial information of MidAmerican Funding, LLC's ("MidAmerican Funding's") investments in subsidiaries is presented under the equity method of accounting. Under this method, the assets and liabilities of subsidiaries are not consolidated. The investments in and advances to subsidiaries are recorded on the Condensed Balance Sheets. The income from operations of the subsidiaries is reported on a net basis as equity in undistributed earnings of subsidiary companies on the Condensed Statements of Operations. The Condensed Statements of Comprehensive Income have been omitted as net income equals comprehensive income for the years ended December 31, 2024, 2023 and 2022.

Income Taxes - MidAmerican Funding is not subject to income tax and is disregarded by the taxing authorities. However, a portion of Berkshire Hathaway Inc.'s consolidated income tax expense has been allocated to MidAmerican Funding for presentation in its separate financial statements commensurate with computing MidAmerican Funding's provision on a stand-alone basis.

Payable to Affiliate - MHC, Inc. ("MHC") settles all obligations of MidAmerican Funding including interest costs on, and repayments of, MidAmerican Funding's long-term debt, income taxes and distributions to parent. MHC paid \$436 million, \$1,037 million and \$81 million in 2024, 2023 and 2022, respectively, on behalf of MidAmerican Funding.

Distributions to Parent - In 2024, 2023 and 2022, MidAmerican Funding declared and paid, via MHC, cash dividends of \$425 million, \$1,025 million and \$69 million, respectively.

See the notes to the consolidated MidAmerican Funding financial statements in Part II, Item 8 for other disclosures.

EXHIBIT INDEX

<u>Exhibit No.</u>	<u>Description</u>

BERKSHIRE HATHAWAY ENERGY

3.1	<u>Fourth Amended and Restated Articles of Incorporation of Berkshire Hathaway Energy Company, effective as of December 30, 2024 (incorporated by reference to Exhibit 3.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated December 31, 2024).</u>
3.2	<u>Amended and Restated Bylaws of Berkshire Hathaway Energy Company (incorporated by reference to Exhibit 3.2 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2005).</u>
4.1	<u>Indenture, dated as of October 4, 2002, by and between MidAmerican Energy Holdings Company and The Bank of New York, Trustee (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Registration Statement No. 333-101699 dated December 6, 2002).</u>
4.2	<u>Fourth Supplemental Indenture, dated as of March 24, 2006, by and between MidAmerican Energy Holdings Company and The Bank of New York Trust Company, N.A., Trustee, relating to the 6.125% Senior Bonds due 2036 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated March 28, 2006).</u>
4.3	<u>Fifth Supplemental Indenture, dated as of May 11, 2007, by and between MidAmerican Energy Holdings Company and The Bank of New York Trust Company, N.A., Trustee, relating to the 5.95% Senior Bonds due 2037 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated May 11, 2007).</u>
4.4	<u>Sixth Supplemental Indenture, dated as of August 28, 2007, by and between MidAmerican Energy Holdings Company and The Bank of New York Trust Company, N.A., Trustee, relating to the 6.50% Senior Bonds due 2037 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated August 28, 2007).</u>
4.5	<u>Ninth Supplemental Indenture, dated as of November 8, 2013, by and between MidAmerican Energy Holdings Company and The Bank of New York Mellon Trust Company, N.A., as Trustee, relating to the 3.750% Senior Notes due 2023 and the 5.150% Senior Notes due 2043 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated November 8, 2013).</u>
4.6	<u>Tenth Supplemental Indenture, dated as December 4, 2014, by and between Berkshire Hathaway Energy Company and The Bank of New York Mellon Trust Company, N.A., as Trustee, relating to the 3.50% Senior Notes due 2025 and the 4.50% Senior Notes due 2045 (incorporated by reference to Exhibit 4.8 to the Berkshire Hathaway Energy Company Registration Statement No. 333-200928 dated December 12, 2014).</u>
4.7	<u>Eleventh Supplemental Indenture, dated as of December 29, 2017, by and between Berkshire Hathaway Energy Company and The Bank of New York Mellon Trust Company, N.A., as trustee, relating to the 6.50% Senior Bonds due 2037 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated January 5, 2018).</u>
4.8	<u>Twelfth Supplemental Indenture, dated as of January 5, 2018, by and between Berkshire Hathaway Energy Company and The Bank of New York Mellon Trust Company, N.A., as trustee, relating to the 2.80% Senior Notes due 2023, the 3.25% Senior Notes due 2028 and the 3.80% Senior Notes due 2048 (incorporated by reference to Exhibit 4.2 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated January 5, 2018).</u>
4.9	<u>Thirteenth Supplemental Indenture, dated as of July 25, 2018, by and between Berkshire Hathaway Energy Company and The Bank of New York Mellon Trust Company, N.A., as trustee, relating to the 4.45% Senior Notes due 2049 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2018).</u>
4.10	<u>Fourteenth Supplemental Indenture, dated as of March 24, 2020, by and between Berkshire Hathaway Energy Company and The Bank of New York Mellon Trust Company, N.A., as trustee, relating to the 4.05% Senior Notes due 2025 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated March 25, 2020).</u>
4.11	<u>Fifteenth Supplemental Indenture, dated as of March 27, 2020, by and between Berkshire Hathaway Energy Company and The Bank of New York Mellon Trust Company, N.A., as trustee, relating to the 3.70% Senior Notes due 2030 and the 4.25% Senior Notes due 2050 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated March 27, 2020).</u>

<u>Exhibit No.</u>	<u>Description</u>
4.12	<u>Sixteenth Supplemental Indenture, dated as of October 29, 2020, by and between Berkshire Hathaway Energy Company and The Bank of New York Mellon Trust Company, N.A., as trustee, relating to the 1.650% Senior Notes due 2031 and the 2.850% Senior Notes due 2051 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated November 2, 2020).</u>
4.13	<u>Seventeenth Supplemental Indenture, dated as of April 21, 2022, by and between Berkshire Hathaway Energy Company and The Bank of New York Mellon Trust Company, N.A., as trustee, relating to the 4.600% Senior Notes due 2053 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated April 25, 2022).</u>
4.14	<u>Indenture, dated as of October 15, 1997, by and between MidAmerican Energy Holdings Company and IBJ Schroder Bank & Trust Company, Trustee (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated October 23, 1997).</u>
4.15	<u>Form of Second Supplemental Indenture, dated as of September 22, 1998 by and between MidAmerican Energy Holdings Company and IBJ Schroder Bank & Trust Company, Trustee, relating to the 8.48% Senior Notes due 2028 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated September 17, 1998).</u>
4.16	<u>Trust Deed, dated as of February 4, 1998 among Yorkshire Power Finance Limited, Yorkshire Power Group Limited and Bankers Trustee Company Limited, Trustee, relating to the £200,000,000 in principal amount of the 7.25% Guaranteed Bonds due 2028 (incorporated by reference to Exhibit 10.74 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).</u>
4.17	<u>First Supplemental Trust Deed, dated as of October 1, 2001, among Yorkshire Power Finance Limited, Yorkshire Power Group Limited and Bankers Trustee Company Limited, Trustee, relating to the £200,000,000 in principal amount of the 7.25% Guaranteed Bonds due 2028 (incorporated by reference to Exhibit 10.75 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).</u>
4.18	<u>Trust Deed dated May 5, 2005 among Northern Electric Finance plc, Northern Electric Distribution Limited, Ambac Assurance UK Limited and HSBC Trustee (C.I.) Limited (incorporated by reference to Exhibit 99.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2005).</u>
4.19	<u>Reimbursement and Indemnity Agreement, dated May 5, 2005 among Northern Electric Finance plc, Northern Electric Distribution Limited and Ambac Assurance UK Limited (incorporated by reference to Exhibit 99.2 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2005).</u>
4.20	<u>Trust Deed, dated May 5, 2005 among Yorkshire Electricity Distribution plc, Ambac Assurance UK Limited and HSBC Trustee (C.I.) Limited (incorporated by reference to Exhibit 99.3 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2005).</u>
4.21	<u>Reimbursement and Indemnity Agreement, dated May 5, 2005 between Yorkshire Electricity Distribution plc and Ambac Assurance UK Limited (incorporated by reference to Exhibit 99.4 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2005).</u>
4.22	<u>Trust Deed, dated as of July 5, 2012, among Northern Powergrid (Yorkshire) plc and HSBC Corporate Trustee Company (UK) Limited, relating to the £150,000,000 in principal amount of the 4.375% Bonds due 2032 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2012).</u>
4.23	<u>Trust Deed, dated as of April 1, 2015, among Northern Powergrid (Yorkshire) plc and HSBC Corporate Trustee Company (UK) Limited, relating to the £150,000,000 in principal amount of the 2.50% Bonds due 2025 (incorporated by reference to Exhibit 4.3 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2015).</u>
4.24	<u>Trust Deed, dated as of November 14, 2023, among Northern Powergrid (Yorkshire) plc and HSBC Corporate Trustee Company (UK) Limited, relating to the £250,000,000 in principal amount of the 5.625% Bonds due 2033 (incorporated by reference to Exhibit 4.26 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2023).</u>
4.25	<u>£120,000,000 Finance Contract, dated December 2, 2015, by and between Northern Powergrid (Northeast) Ltd and the European Investment Bank (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2016).</u>

<u>Exhibit No.</u>	<u>Description</u>
4.26	<u>Guarantee and Indemnity Agreement, dated December 8, 2015, by and between Northern Powergrid Holdings Company and the European Investment Bank (incorporated by reference to Exhibit 4.2 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2016).</u>
4.27	<u>£130,000,000 Finance Contract, dated December 2, 2015, by and between Northern Powergrid (Yorkshire) plc and the European Investment Bank (incorporated by reference to Exhibit 4.3 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2016).</u>
4.28	<u>Guarantee and Indemnity Agreement, dated December 8, 2015, by and between Northern Powergrid Holdings Company and the European Investment Bank (incorporated by reference to Exhibit 4.4 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2016).</u>
4.29	<u>Deed of Amendment and Consent, dated March 1, 2016, by and between Northern Powergrid Holdings Company, Northern Powergrid (Yorkshire) plc and the European Investment Bank (incorporated by reference to Exhibit 4.5 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2016).</u>
4.30	<u>Trust Deed, dated as of May 24, 2019, among Northern Electric Finance plc, Northern Powergrid (Northeast) Limited, and HSBC Corporate Trustee Company (UK) Limited, relating to the £150,000,000 in principal amount of the 2.75% Guaranteed Bonds due 2049 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2019).</u>
4.31	<u>Trust Deed, dated as of October 9, 2019, among Northern Powergrid (Yorkshire) plc and HSBC Corporate Trustee Company (UK) Limited, relating to the £300,000,000 in principal amount of the 2.25% Guaranteed Bonds due 2059 (incorporated by reference to Exhibit 4.3 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2019).</u>
4.32	<u>Trust Deed, dated as of June 16, 2020, by and between Northern Powergrid (Northeast) plc and HSBC Corporate Trustee Company (UK) Limited, Trustee, relating to the £300,000,000 in principal amount of 1.875% Green Bonds due 2062 (incorporated by reference to Exhibit 4.3 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2020).</u>
4.33	<u>Trust Deed, dated as of April 1, 2022, among Northern Powergrid (Northeast) plc and HSBC Corporate Trustee Company (UK) Limited, relating to the £350,000,000 in principal amount of the 3.250% Bonds due 2052 (incorporated by reference to Exhibit 4.2 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2022).</u>
4.34	<u>Fiscal Agency Agreement, dated February 12, 2007, by and between Northern Natural Gas Company and The Bank of New York Trust Company, N.A., Fiscal Agent, relating to the \$150,000,000 in principal amount of the 5.80% Senior Bonds due 2037 (incorporated by reference to Exhibit 99.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated February 12, 2007).</u>
4.35	<u>Fiscal Agency Agreement, dated August 27, 2012, by and between Northern Natural Gas Company and The Bank of New York Mellon Trust Company, N.A., Fiscal Agent, relating to the \$250,000,000 in principal amount of the 4.10% Senior Bonds due 2042 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2012).</u>
4.36	<u>Fiscal Agency Agreement, dated as of July 17, 2018, by and between Northern Natural Gas Company and The Bank of New York Mellon Trust Company, N.A., Fiscal Agent, relating to the \$450,000,000 in principal amount of the 4.30% Senior Bonds due 2049 (incorporated by reference to Exhibit 4.2 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2018).</u>
4.37	<u>Amendment No. 1 to the Fiscal Agency Agreement, dated as of July 17, 2018, by and between Northern Natural Gas Company and The Bank of New York Mellon Trust Company, N.A., Fiscal Agent, relating to an additional \$200,000,000 in principal amount of the 4.30% Senior Bonds due 2049 (incorporated by reference to Exhibit 4.2 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2019).</u>
4.38	<u>Fiscal Agency Agreement, dated as of April 9, 2021, by and between Northern Natural Gas Company and The Bank of New York Mellon Trust Company, N.A., Fiscal Agent, relating to the \$550,000,000 in principal amount of the 3.40% Senior Notes due 2051 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2021).</u>

<u>Exhibit No.</u>	<u>Description</u>
4.39	<u>Fiscal Agency Agreement, dated as of January 31, 2024, by and between Northern Natural Gas Company and The Bank of New York Mellon Trust Company, N.A., Fiscal Agent, relating to the \$500,000,000 in principal amount of the 5.625% Senior Notes due 2054 (incorporated by reference to Exhibit 4.41 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2023).</u>
4.40	<u>Amended and Restated Master Trust Indenture, dated April 28, 2003, by and between AltaLink, L.P., AltaLink Management Ltd. and BMO Trust Company (incorporated by reference to Exhibit 4.99 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).</u>
4.41	<u>Seventh Supplemental Indenture, dated April 28, 2003, by and between AltaLink, L.P., AltaLink Management Ltd. and BMO Trust Company (incorporated by reference to Exhibit 4.100 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).</u>
4.42	<u>Ninth Supplemental Indenture, dated May 9, 2006, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.101 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).</u>
4.43	<u>Twelfth Supplemental Indenture, dated August 18, 2010, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.103 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).</u>
4.44	<u>Sixteenth Supplemental Indenture, dated November 15, 2012, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.104 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).</u>
4.45	<u>Eighteenth Supplemental Indenture, dated October 24, 2014, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.106 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).</u>
4.46	<u>Nineteenth Supplemental Indenture, dated October 24, 2014, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.107 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).</u>
4.47	<u>Twentieth Supplemental Indenture, dated June 30, 2015, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada, relating to C\$350,000,000 in principal amount of the 4.09% Series 2015-1 Medium-Term Notes due 2045 (incorporated by reference to Exhibit 4.5 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2015).</u>
4.48	<u>Twenty-First Supplemental Indenture, dated December 14, 2018, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.64 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2018).</u>
4.49	<u>Twenty-Third Supplemental Indenture, dated as of September 11, 2020, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada, as trustee, relating to the C\$225,000,000 in principal amount of the 1.509% Series 2020-1 Senior Secured Notes due 2030 (incorporated by reference to Exhibit 4.5 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2020).</u>
4.50	<u>Twenty-Fourth Supplemental Indenture, dated as of November 28, 2022, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada, as trustee, relating to the C\$275,000,000 in principal amount of the 4.692% Series 2022-1 Senior Secured Notes due 2032 (incorporated by reference to Exhibit 4.54 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2022).</u>
4.51	<u>Twenty-Fifth Supplemental Indenture, dated as of October 11, 2023, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada, as trustee, relating to the C\$500,000,000 in principal amount of the 5.463% Series 2023-1 Senior Secured Notes due 2055 (incorporated by reference to Exhibit 4.1 to Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2023).</u>

<u>Exhibit No.</u>	<u>Description</u>
4.52	<u>Twenty-Sixth Supplemental Indenture, dated as of May 22, 2024, by and between AltaLink, L.P., AltaLink Management Ltd., and BNY Trust Company of Canada, as trustee, relating to the C\$325,000,000 in principal amount of the 4.742% Series 2024-1 Senior Secured Notes due 2054 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2024).</u>
4.53	<u>Indenture, dated as of February 24, 2012, by and between Topaz Solar Farms LLC and The Bank of New York Mellon Trust Company, N.A., as Trustee, relating to the \$850,000,000 in principal amount of the 5.75% Series A Senior Secured Notes due 2039 (incorporated by reference to Exhibit 4.56 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2011).</u>
4.54	<u>First Supplemental Indenture, dated as of April 15, 2013, between Topaz Solar Farms LLC, as Issuer, and The Bank of New York Mellon Trust Company, N.A., as Trustee, relating to the \$250,000,000 in principal amount of the 4.875% Series B Senior Secured Notes due 2039 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2013).</u>
4.55	<u>Indenture, dated as of June 27, 2013, between Solar Star Funding, LLC, as Issuer, and Wells Fargo Bank, National Association, as Trustee, relating to the \$1,000,000,000 in principal amount of the 5.375% Series A Senior Secured Notes due 2035 (incorporated by reference to Exhibit 4.2 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2013).</u>
4.56	<u>First Supplemental Indenture, dated as of March 12, 2015, between Solar Star Funding, LLC, as Issuer, and Wells Fargo Bank, National Association, as Trustee, relating to the \$325,000,000 in principal amount of the 3.95% Series B Senior Secured Notes due 2035 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2015).</u>
10.1	<u>Second Amendment to the \$3,500,000,000 Third Amended and Restated Credit Agreement, dated as of June 28, 2024, among Berkshire Hathaway Energy Company, as Borrower, the Banks, Financial Institutions and Other Institutional Lenders, as Initial Lenders, MUFG Bank, LTD., as Administrative Agent and the LC Issuing Banks (incorporated by reference to Exhibit 10.2 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2024).</u>
10.2	<u>Amended and Restated £200,000,000 Facility Agreement, dated as of December 22, 2021, among Northern Powergrid Holdings Company, as Guarantor, Northern Powergrid (Yorkshire) plc and Northern Powergrid (Northeast) Limited, as Borrowers, and Santander UK plc, Lloyds Bank plc and National Westminster Bank plc, as Original Lenders (incorporated by reference to Exhibit 10.2 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2021).</u>
10.3	<u>Sixth Amended and Restated Credit Agreement, dated as of March 22, 2024 among AltaLink Investments, L.P., as borrower, AltaLink Investment Management LTD., as general partner, Royal Bank of Canada, as administrative agent, and Lenders (redacted) (incorporated by reference to Exhibit 10.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2024).</u>
10.4	<u>First Amending Agreement to the Sixth Amended and Restated Credit Agreement, dated as of December 16, 2024 among AltaLink Investments, L.P., as borrower, AltaLink Investment Management LTD., as general partner, Royal Bank of Canada, as administrative agent, and Lenders.</u>
10.5	<u>Fifth Amended and Restated Credit Agreement, dated as of December 15, 2023, among AltaLink L.P., as borrower, AltaLink Management Ltd., as general partner, The Bank of Nova Scotia, as administrative agent, and Lenders (redacted) (incorporated by reference to Exhibit 10.7 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2023).</u>
10.6	<u>First Amending Agreement to the Fifth Amended and Restated Credit Agreement, dated as of December 16, 2024, among AltaLink L.P., as borrower, AltaLink Management Ltd., as general partner, The Bank of Nova Scotia, as administrative agent, and Lenders.</u>
10.7	<u>Sixth Amended and Restated Credit Agreement, dated as of December 15, 2023, among AltaLink, L.P., as borrower, AltaLink Management Ltd., as general partner, The Bank of Nova Scotia, as administrative agent and Lenders (redacted) (incorporated by reference to Exhibit 10.8 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2023).</u>
10.8	<u>First Amending Agreement to the Sixth Amended and Restated Credit Agreement, dated as of December 16, 2024, among AltaLink, L.P., as borrower, AltaLink Management Ltd., as general partner, The Bank of Nova Scotia, as administrative agent and Lenders.</u>
10.9	<u>Credit Agreement, dated as of December 22, 2023, among BHE Canada Holdings Corporation, as borrower, Bank of Montreal, as administrative agent, and Lenders (redacted) (incorporated by reference to Exhibit 10.12 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2023).</u>

<u>Exhibit No.</u>	<u>Description</u>
10.10	<u>Berkshire Hathaway Energy Company Executive Voluntary Deferred Compensation Plan restated effective as of January 1, 2007 (incorporated by reference to Exhibit 10.9 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2007).</u>
10.11	<u>Berkshire Hathaway Energy Company Long-Term Incentive Partnership Plan as Amended and Restated December 31, 2021 (incorporated by reference to Exhibit 10.11 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2021).</u>
14.1	<u>Berkshire Hathaway Energy Company Code of Ethics For Chief Executive Officer, Chief Financial Officer and Other Covered Officers (incorporated by reference to Exhibit 14.1 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2015).</u>
21.1	<u>Subsidiaries of the Registrant.</u>
23.1	<u>Consent of Deloitte & Touche LLP.</u>
24.1	<u>Power of Attorney.</u>
31.1	<u>Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.</u>
31.2	<u>Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.</u>
32.1	<u>Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.</u>
32.2	<u>Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.</u>

PACIFICORP

3.3	<u>Fourth Restated Article of Incorporation of PacifiCorp, as amended January 31, 2025.</u>
3.4	<u>Bylaws of PacifiCorp, as amended December 16, 2024 (incorporated by reference to Exhibit 3.1 to the PacifiCorp Current Report on Form 8-K dated December 16, 2024).</u>
14.2	<u>Code of Ethics (incorporated by reference to Exhibit 14.1 to the PacifiCorp Transition Report on Form 10-K for the nine-month period ended December 31, 2006).</u>
23.2	<u>Consent of Deloitte & Touche LLP.</u>
31.3	<u>Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.</u>
31.4	<u>Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.</u>
32.3	<u>Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.</u>
32.4	<u>Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.</u>

BERKSHIRE HATHAWAY ENERGY AND PACIFICORP

4.57	Mortgage and Deed of Trust dated as of January 9, 1989, between PacifiCorp and The Bank of New York Mellon Trust Company, N.A., as successor Trustee, incorporated by reference to Exhibit 4-E to the PacifiCorp Form 8-B, as supplemented and modified by the following Supplemental Indentures each incorporated by reference:

<u>Exhibit Number</u>	<u>PacifiCorp File Type</u>	<u>File Date</u>
(4)(b) ^(a)	SE	November 2, 1989
(4)(a) ^(a)	8-K	January 9, 1990
(4)(a) ^(a)	8-K	September 11, 1991
(4)(a) ^(a)	8-K	January 7, 1992
(4)(a) ^(a)	10-Q	Quarter ended March 31, 1992
(4)(a) ^(a)	10-Q	Quarter ended September 30, 1992
(4)(a) ^(a)	8-K	April 1, 1993
(4)(a) ^(a)	10-Q	Quarter ended September 30, 1993
<u>(4)a</u>	10-Q	Quarter ended June 30, 1994
<u>(4)b</u>	10-K	Year ended December 31, 1994

<u>Exhibit No.</u>	<u>Description</u>
	(4)b 10-K Year ended December 31, 1995
	(4)b 10-K Year ended December 31, 1996
	(4)b 10-K Year ended December 31, 1998
	99(a) 8-K November 21, 2001
	4.1 10-Q Quarter ended June 30, 2003
	99 8-K September 9, 2003
	4 8-K August 26, 2004
	4 8-K June 14, 2005
	4.2 8-K August 14, 2006
	4 8-K March 14, 2007
	4.1 8-K October 3, 2007
	4.1 8-K July 17, 2008
	4.1 8-K January 8, 2009
	4.1 8-K May 12, 2011
	4.1 8-K January 6, 2012
	4.1 8-K June 6, 2013
	4.1 8-K March 13, 2014
	4.1 8-K June 19, 2015
	4.1 8-K July 13, 2018
	4.1 8-K March 1, 2019
	4.1 8-K April 8, 2020
	4.1 8-K July 9, 2021
	4.1 8-K December 1, 2022
	4.1 8-K May 15, 2023
	4.1 8-K January 3, 2024
10.12	Second Amendment to the \$2,000,000,000 Third Amended and Restated Credit Agreement, dated as of June 28, 2024, among PacifiCorp, as Borrower, the Banks, Financial Institutions and Other Institutional Lenders, as Initial Lenders, JPMorgan Chase Bank, N.A., as Administrative Agent and the LC Issuing Banks (incorporated by reference to Exhibit 10.5 to the PacifiCorp Quarterly Report on Form 10-Q for the quarter ended June 30, 2024).
10.13	\$900,000,000 364-Day Credit Agreement, dated as of June 28, 2024, among PacifiCorp, as Borrower, the Banks, Financial Institutions and Other Institutional Lenders, as Initial Lenders, and JPMorgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.4 to the PacifiCorp Quarterly Report on Form 10-Q for the quarter ended June 30, 2024).
95	Mine Safety Disclosures Required by the Dodd-Frank Wall Street Reform and Consumer Protection Act.

Exhibit No.	Description

MIDAMERICAN ENERGY

3.5	<u>Restated Articles of Incorporation of MidAmerican Energy Company, as amended October 27, 1998. (incorporated by reference to Exhibit 3.3 to the MidAmerican Energy Company Quarterly Report on Form 10-Q for the quarter ended September 30, 1998).</u>
3.6	<u>Restated Bylaws of MidAmerican Energy Company, as amended July 24, 1996. (incorporated by reference to Exhibit 3.1 to the MidAmerican Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 1996).</u>
14.3	<u>Code of Ethics for Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer. (incorporated by reference to Exhibit 14.1 to the MidAmerican Energy Company Annual Report on Form 10-K for the year ended December 31, 2003).</u>
23.3	<u>Consent of Deloitte & Touche LLP.</u>
31.5	<u>Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.</u>
31.6	<u>Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.</u>
32.5	<u>Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.</u>
32.6	<u>Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.</u>

MIDAMERICAN FUNDING

3.7	<u>Articles of Organization of MidAmerican Funding, LLC (incorporated by reference to Exhibit 3.1 to the MidAmerican Funding, LLC Registration Statement No. 333-90553 dated November 8, 1999).</u>
3.8	<u>Operating Agreement of MidAmerican Funding, LLC (incorporated by reference to Exhibit 3.2 to the MidAmerican Funding, LLC Registration Statement No. 333-90553 dated November 8, 1999).</u>
3.9	<u>Amendment No. 1 to the Operating Agreement of MidAmerican Funding, LLC dated as of February 9, 2010 (incorporated by reference to Exhibit 3.3 to the MidAmerican Funding, LLC Annual Report on Form 10-K for the year ended December 31, 2009).</u>
14.4	<u>Code of Ethics for Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer (incorporated by reference to Exhibit 14.2 to the MidAmerican Funding, LLC Annual Report on Form 10-K for the year ended December 31, 2003).</u>
31.7	<u>Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.</u>
31.8	<u>Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.</u>
32.7	<u>Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.</u>
32.8	<u>Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.</u>

BERKSHIRE HATHAWAY ENERGY, MIDAMERICAN ENERGY AND MIDAMERICAN FUNDING

4.58	<u>Form of Indenture, by and between MidAmerican Energy Company and The Bank of New York, Trustee (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Registration Statement No. 333-59760 dated January 31, 2002).</u>
4.59	<u>First Supplemental Indenture, dated as of February 8, 2002, by and between MidAmerican Energy Company and The Bank of New York, Trustee (incorporated by reference to Exhibit 4.3 to the MidAmerican Energy Company Annual Report on Form 10-K for the year ended December 31, 2004).</u>
4.60	<u>Fourth Supplemental Indenture, dated November 1, 2005, by and between MidAmerican Energy Company and The Bank of New York Trust Company, NA, Trustee (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Annual Report on Form 10-K for the year ended December 31, 2005).</u>
4.61	<u>Indenture, dated as of October 1, 2006, by and between MidAmerican Energy Company and The Bank of New York Trust Company, N.A., Trustee (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2006).</u>
4.62	<u>First Supplemental Indenture, dated as of October 6, 2006, by and between MidAmerican Energy Company and The Bank of New York Trust Company, N.A., Trustee relating to the 5.80% Notes due 2036 (incorporated by reference to Exhibit 4.2 to the MidAmerican Energy Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2006).</u>

<u>Exhibit No.</u>	<u>Description</u>
4.63	<u>Indenture, dated as of September 9, 2013, between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Current Report on Form 8-K dated September 13, 2013).</u>
4.64	<u>First Supplemental Indenture, dated as of September 19, 2013, between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Current Report on Form 8-K dated September 19, 2013).</u>
4.65	<u>Specimen of 4.80% First Mortgage Bonds due 2043 (incorporated by reference to Exhibit 4.4 to the MidAmerican Energy Company Current Report on Form 8-K dated September 19, 2013).</u>
4.66	<u>Amendment No. 1 to the First Supplemental Indenture, dated as of April 3, 2014, by and between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of September 9, 2013 (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Current Report on Form 8-K dated April 3, 2014).</u>
4.67	<u>Second Supplemental Indenture, dated as of April 3, 2014, by and between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of September 9, 2013 (incorporated by reference to Exhibit 4.2 to the MidAmerican Energy Company Current Report on Form 8-K dated April 3, 2014).</u>
4.68	<u>Specimen of 4.40% First Mortgage Bonds due 2044 (incorporated by reference to Exhibit 4.5 to the MidAmerican Energy Company Current Report on Form 8-K dated April 3, 2014).</u>
4.69	<u>Amendment No. 1 to the Second Supplemental Indenture, dated as of October 15, 2015, by and between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of September 9, 2013 (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Current Report on Form 8-K dated October 15, 2015).</u>
4.70	<u>Third Supplemental Indenture, dated as of October 15, 2015, by and between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of September 9, 2013 (incorporated by reference to Exhibit 4.2 to the MidAmerican Energy Company Current Report on Form 8-K dated October 15, 2015).</u>
4.71	<u>Specimen of 4.25% First Mortgage Bonds due 2046 (incorporated by reference to Exhibit 4.4 to the MidAmerican Energy Company Current Report on Form 8-K dated October 15, 2015).</u>
4.72	<u>Fourth Supplemental Indenture, dated as of December 8, 2016, by and between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of September 9, 2013 (incorporated by reference to Exhibit 4.96 to the MidAmerican Energy Company Annual Report on Form 10-K for the year ended December 31, 2016).</u>
4.73	<u>Fifth Supplemental Indenture, dated as of February 1, 2017, by and between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of September 9, 2013 (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Current Report on Form 8-K dated February 1, 2017).</u>
4.74	<u>Specimen of 3.10% First Mortgage Bonds due 2027 (incorporated by reference to Exhibit 4.2 to the MidAmerican Energy Company Current Report on Form 8-K dated February 1, 2017).</u>
4.75	<u>Specimen of 3.95% First Mortgage Bonds due 2047 (incorporated by reference to Exhibit 4.3 to the MidAmerican Energy Company Current Report on Form 8-K dated February 1, 2017).</u>
4.76	<u>Sixth Supplemental Indenture, dated as of December 14, 2017, by and between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of September 9, 2013 (incorporated by reference to Exhibit 4.91 to the MidAmerican Energy Company Annual Report on Form 10-K for the year ended December 31, 2017).</u>
4.77	<u>Seventh Supplemental Indenture, dated as of February 1, 2018, by and between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of September 9, 2013 (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Current Report on Form 8-K dated February 1, 2018).</u>
4.78	<u>Specimen of 3.65% First Mortgage Bonds due 2048 (incorporated by reference to Exhibit 4.2 to the MidAmerican Energy Company Current Report on Form 8-K dated February 1, 2018).</u>
4.79	<u>Eighth Supplemental Indenture, dated January 9, 2019, by and between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of September 9, 2013 (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Current Report on Form 8-K dated January 9, 2019).</u>
4.80	<u>Specimen of 3.65% First Mortgage Bonds due 2029 (incorporated by reference to Exhibit 4.2 to the MidAmerican Energy Company Current Report on Form 8-K dated January 9, 2019).</u>

<u>Exhibit No.</u>	<u>Description</u>
4.81	<u>Specimen of 4.25% First Mortgage Bonds due 2049 (incorporated by reference to Exhibit 4.3 to the MidAmerican Energy Company Current Report on Form 8-K dated January 9, 2019).</u>
4.82	<u>Amendment No. 1 to the Eighth Supplemental Indenture, dated as of October 15, 2019, by and between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of September 9, 2013 (incorporated by reference to Exhibit 4.3 to the MidAmerican Energy Company Current Report on Form 8-K dated October 15, 2019).</u>
4.83	<u>Ninth Supplemental Indenture, dated as of October 15, 2019, by and between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of September 9, 2013 (incorporated by reference to Exhibit 4.4 to the MidAmerican Energy Company Current Report on Form 8-K dated October 15, 2019).</u>
4.84	<u>Specimen of 3.15% First Mortgage Bond due 2050 (incorporated by reference to Exhibit 4.4 to the MidAmerican Energy Company Current Report on Form 8-K dated October 15, 2019).</u>
4.85	<u>Tenth Supplemental Indenture, dated as of July 22, 2021, by and between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of September 9, 2013 (incorporated by reference to Exhibit 4.3 to the MidAmerican Energy Company Current Report on Form 8-K dated July 22, 2021).</u>
4.86	<u>Specimen of the 2.70% First Mortgage Bonds due 2052 (incorporated by reference to Exhibit 4.4 to the MidAmerican Energy Company Current Report on Form 8-K dated July 22, 2021).</u>
4.87	<u>Eleventh Supplemental Indenture, dated as of September 7, 2023, by and between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of September 9, 2013 (incorporated by reference to Exhibit 4.3 to the MidAmerican Energy Company Current Report on Form 8-K dated September 7, 2023).</u>
4.88	<u>Specimen of the 5.350% First Mortgage Bonds due 2034 (incorporated by reference to Exhibit 4.4 to the MidAmerican Energy Company Current Report on Form 8-K dated September 7, 2023).</u>
4.89	<u>Specimen of the 5.850% First Mortgage Bonds due 2054 (incorporated by reference to Exhibit 4.5 to the MidAmerican Energy Company Current Report on Form 8-K dated September 7, 2023).</u>
4.90	<u>Twelfth Supplemental Indenture, dated January 24, 2024, by and between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated by reference to Exhibit 4.3 to the MidAmerican Energy Company Current Report on Form 8-K dated January 24, 2024).</u>
4.91	<u>Specimen of the 5.300% First Mortgage Bonds due 2055 (incorporated by reference to Exhibit 4.4 to the MidAmerican Energy Company Current Report on Form 8-K dated January 24, 2024).</u>
4.92	<u>Mortgage, Security Agreement, Fixture Filing and Financing Statement, dated as of September 9, 2013, from MidAmerican Energy Company to The Bank of New York Mellon Trust Company, N.A., as collateral trustee (incorporated by reference to Exhibit 4.2 to the MidAmerican Energy Company Current Report on Form 8-K dated September 13, 2013).</u>
4.93	<u>Intercreditor and Collateral Trust Agreement, dated as of September 9, 2013, among MidAmerican Energy Company, The Bank of New York Mellon Trust Company, N.A., as trustee, and The Bank of New York Mellon Trust Company, N.A., as collateral trustee (incorporated by reference to Exhibit 4.3 to the MidAmerican Energy Company Current Report on Form 8-K dated September 13, 2013).</u>
4.94	<u>Form of Indenture, between MidAmerican Energy Company and the Trustee, (Senior Unsecured Debt Securities) (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Registration Statement No. 333-192077 dated November 4, 2013).</u>
4.95	<u>Form of Indenture, between MidAmerican Energy Company and the Trustee, (Subordinated Unsecured Debt Securities) (incorporated by reference to Exhibit 4.2 to the MidAmerican Energy Company Registration Statement No. 333-192077 dated November 4, 2013).</u>
10.14	<u>Second Amendment to the \$1,500,000,000 Third Amended and Restated Credit Agreement, dated as of June 28, 2024, among MidAmerican Energy Company, as Borrower, the Banks, Financial Institutions and Other Institutional Lenders, as Initial Lenders, Mizuho Bank, Ltd., as Administrative Agent and the LC Issuing Banks (incorporated by reference to Exhibit 10.6 to the MidAmerican Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2024).</u>

BERKSHIRE HATHAWAY ENERGY AND MIDAMERICAN FUNDING

4.96	<u>Indenture and First Supplemental Indenture, dated March 11, 1999, by and between MidAmerican Funding, LLC and IBJ Whitehall Bank & Trust Company, Trustee, relating to the \$325 million Senior Bonds (incorporated by reference to Exhibits 4.1 and 4.2 to the MidAmerican Funding, LLC Registration Statement No. 333-905333 dated November 8, 1999).</u>

<u>Exhibit No.</u>	<u>Description</u>
<u>NEVADA POWER</u>	
3.10	<u>Restated Articles of Incorporation of Nevada Power Company, dated July 28, 1999 (incorporated by reference to Exhibit 3(B) to the Nevada Power Company Annual Report on Form 10-K for the year ended December 31, 1999).</u>
3.11	<u>Amended and Restated Bylaws of Nevada Power Company as amended December 21, 2017 (incorporated by reference to Exhibit 3.1 to the Nevada Power Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2018).</u>
4.97	<u>Financing Agreement dated May 1, 2017 between Clark County, Nevada and Nevada Power Company (relating to Clark County, Nevada's \$39,500,000 Pollution Control Refunding Revenue Bonds (Nevada Power Company Project) Series 2017) (incorporated by reference to Exhibit 4.1 to the Nevada Power Company Current Report on Form 8-K dated May 25, 2017).</u>
4.98	<u>Financing Agreement dated May 1, 2017 between the Coconino County, Arizona Pollution Control Corporation and Nevada Power Company (relating to the Coconino County, Arizona Pollution Control Corporation's \$53,000,000 Pollution Control Refunding Revenue Bonds (Nevada Power Company Projects) Series 2017A and 2017B) (incorporated by reference to Exhibit 4.2 to the Nevada Power Company Current Report on Form 8-K dated May 25, 2017).</u>
10.15	<u>Transmission Use and Capacity Exchange Agreement between Nevada Power Company, Sierra Pacific Power Company and Great Basin Transmission, LLC dated August 20, 2010 (incorporated by reference to Exhibit 10.1 to the Nevada Power Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2010).</u>
14.5	<u>Code of Ethics for Chief Executive Officer, Chief Financial Officer and Other Covered Officers (incorporated by reference to Exhibit 14.1 to the Nevada Power Company Annual Report on Form 10-K for the year ended December 31, 2013).</u>
23.4	<u>Consent of Deloitte & Touche LLP.</u>
31.9	<u>Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.</u>
31.10	<u>Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.</u>
32.9	<u>Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.</u>
32.10	<u>Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.</u>
<u>BERKSHIRE HATHAWAY ENERGY AND NEVADA POWER</u>	
4.99	<u>General and Refunding Mortgage Indenture, dated May 1, 2001, between Nevada Power Company and The Bank of New York, as Trustee (incorporated by reference to Exhibit 4.1(a) to the Nevada Power Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2001).</u>
4.100	<u>Second Supplemental Indenture, dated as of October 1, 2001 (incorporated by reference to Exhibit 4(A) to the Nevada Power Company Annual Report on Form 10-K for the year ended December 31, 2001).</u>
4.101	<u>Officer's Certificate establishing the terms of Nevada Power Company's 6.65% General and Refunding Mortgage Notes, Series N, due 2036 (incorporated by reference to Exhibit 4.1 to the Nevada Power Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2006).</u>
4.102	<u>Officer's Certificate establishing the terms of Nevada Power Company's 6.75% General and Refunding Mortgage Notes, Series R, due 2037 (incorporated by reference to Exhibit 4.1 to the Nevada Power Company Current Report on Form 8-K dated June 27, 2007).</u>
4.103	<u>Officer's Certificate establishing the terms of Nevada Power Company 5.375% General and Refunding Mortgage Notes, Series X, due 2040 (incorporated by reference to Exhibit 4.1 to Nevada Power Company Current Report on Form 8-K dated September 10, 2010).</u>
4.104	<u>Officer's Certificate establishing the terms of Nevada Power Company 5.45% General and Refunding Mortgage Notes, Series Y, due 2041 (incorporated by reference to Exhibit 4.1 to the Nevada Power Company Current Report on Form 8-K dated May 10, 2011).</u>
4.105	<u>Officer's Certificate establishing the terms of Nevada Power Company's General and Refunding Mortgage Notes, Series AA (Nos. AA-1 and AA-2) (incorporated by reference to Exhibit 4.3 to the Nevada Power Company Current Report on Form 8-K dated May 25, 2017).</u>

<u>Exhibit No.</u>	<u>Description</u>
4.106	<u>Officer's Certificate establishing the terms of Nevada Power Company's 3.70% General and Refunding Mortgage Notes, Series CC, due 2029 (incorporated by reference to Exhibit 4.1 to the Nevada Power Company Current Report on Form 8-K dated January 30, 2019).</u>
4.107	<u>Officer's Certificate establishing the terms of Nevada Power Company's 2.40% General and Refunding Mortgage Notes, Series DD, due 2030 (incorporated by reference to Exhibit 4.1 to the Nevada Power Company Current Report on Form 8-K dated January 30, 2020).</u>
4.108	<u>Officer's Certificate establishing the terms of Nevada Power Company's 3.125% General and Refunding Mortgage Notes, Series EE, due 2050 (incorporated by reference to Exhibit 4.2 to the Nevada Power Company Current Report on Form 8-K dated January 30, 2020).</u>
4.109	<u>Officer's Certificate establishing the terms of Nevada Power Company's 5.90% General and Refunding Mortgage Notes, Series GG, due 2053 (incorporated by reference to Exhibit 4.1 to the Nevada Power Company Current Report on Form 8-K dated October 20, 2022).</u>
4.110	<u>Officer's Certificate establishing the terms of Nevada Power Company's 6.000% General and Refunding Mortgage Notes, Series 2023A, due 2054 (incorporated by reference to Exhibit 4.1 to the Nevada Power Company Current Report on Form 8-K dated September 14, 2023).</u>
4.111	<u>Indenture, dated as of February 3, 2025, by and between Nevada Power Company and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated by reference to Exhibit 4.1 to the Nevada Power Company Current Report on Form 8-K dated February 5, 2025).</u>
4.112	<u>First Supplemental Indenture, dated as of February 3, 2025, by and between Nevada Power Company and The Bank of New York Mellon Trust Company, N.A., as trustee relating to the 6.250% Fixed-to-Fixed Reset Rate Junior Subordinated Notes due 2055 (incorporated by reference to Exhibit 4.2 to the Nevada Power Company Current Report on Form 8-K dated February 5, 2025).</u>
10.16	<u>Second Amendment to the \$600,000,000 Fifth Amended and Restated Credit Agreement, dated as of June 28, 2024, among Nevada Power Company, as Borrower, the Banks, Financial Institutions and Other Institutional Lenders, as Initial Lenders, Wells Fargo Bank, National Association, as Administrative Agent and the LC Issuing Banks (incorporated by reference to Exhibit 10.7 to the Nevada Power Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2024).</u>

SIERRA PACIFIC

3.12	<u>Restated Articles of Incorporation of Sierra Pacific Power Company, dated January 23, 2019 (incorporated by reference to Exhibit 3.2 to the Sierra Pacific Power Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2023).</u>
3.13	<u>Amended and Restated Bylaws of Sierra Pacific Power Company as amended December 21, 2017 (incorporated by reference to Exhibit 3.2 to the Sierra Pacific Power Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2018).</u>
4.113	<u>Financing Agreement dated May 1, 2016 between Washoe County, Nevada and Sierra Pacific Power Company (relating to Washoe County, Nevada's \$80,000,000 Water Facilities Refunding Revenue Bonds (Sierra Pacific Power Company Project) Series 2016C, 2016D and 2016E) (incorporated by reference to Exhibit 4.1 to the Sierra Pacific Power Company Current Report on Form 8-K dated May 24, 2016).</u>
4.114	<u>Financing Agreement dated May 1, 2016 between Washoe County, Nevada and Sierra Pacific Power Company (relating to Washoe County, Nevada's \$213,930,000 Gas Facilities Refunding Revenue Bonds, Gas and Water Facilities Refunding Revenue Bonds and Water Facilities Refunding Revenue Bonds (Sierra Pacific Power Company Projects) Series 2016A, 2016B, 2016F and 2016G (incorporated by reference to Exhibit 4.2 to the Sierra Pacific Power Company Current Report on Form 8-K dated May 24, 2016).</u>
4.115	<u>Financing Agreement dated May 1, 2016 between Humboldt County, Nevada and Sierra Pacific Power Company (relating to Humboldt County, Nevada's \$49,750,000 Pollution Control Refunding Revenue Bonds (Sierra Pacific Power Company Project) Series 2016A and 2016B (incorporated by reference to Exhibit 4.3 to the Sierra Pacific Power Company Current Report on Form 8-K dated May 24, 2016).</u>
10.17	<u>Transmission Use and Capacity Exchange Agreement between Nevada Power Company, Sierra Pacific Power Company and Great Basin Transmission, LLC dated August 20, 2010 (incorporated by reference to Exhibit 10.1 to the Sierra Pacific Power Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2010).</u>
10.18	<u>\$200,000,000 Demand Promissory Note, dated as of April 14, 2022, among Sierra Pacific Power Company, as the Maker, and NV Energy Inc., as the Holder (incorporated by reference to Exhibit 10.1 to the Sierra Pacific Power Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2022).</u>

<u>Exhibit No.</u>	<u>Description</u>
14.6	<u>Code of Ethics for Chief Executive Officer, Chief Financial Officer and Other Covered Officers (incorporated by reference to Exhibit 14.1 to the Sierra Pacific Power Company Annual Report on Form 10-K for the year ended December 31, 2013).</u>
31.11	<u>Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.</u>
31.12	<u>Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.</u>
32.11	<u>Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.</u>
32.12	<u>Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.</u>

BERKSHIRE HATHAWAY ENERGY AND SIERRA PACIFIC

4.116	<u>General and Refunding Mortgage Indenture, dated as of May 1, 2001, between Sierra Pacific Power Company and The Bank of New York, as Trustee (incorporated by reference to Exhibit 4.2(a) to the Sierra Pacific Power Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2001).</u>
4.117	<u>Second Supplemental Indenture, dated as of October 30, 2006, to subject additional properties of Sierra Pacific Power Company located in the State of California to the lien of the General and Refunding Mortgage Indenture and to correct defects in the original Indenture (incorporated by reference to Exhibit 4(A) to the Sierra Pacific Power Company Annual Report on Form 10-K for the year ended December 31, 2006).</u>
4.118	<u>Third Supplemental Indenture, dated as of May 31, 2022, by and between Sierra Pacific Power Company and the Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.3 to the Sierra Pacific Power Company Current Report on Form 8-K dated September 18, 2023).</u>
4.119	<u>Officer's Certificate establishing the terms of Sierra Pacific Power Company's 6.75% General and Refunding Mortgage Notes, Series P, due 2037 (incorporated by reference to Exhibit 4.2 to the Sierra Pacific Power Company Current Report on Form 8-K dated June 27, 2007).</u>
4.120	<u>Officer's Certificate establishing the terms of Sierra Pacific Power Company's 2.60% General and Refunding Mortgage Notes, Series U, due 2026 (incorporated by reference to Exhibit 4.1 to the Sierra Pacific Power Company Current Report on Form 8-K dated April 15, 2016).</u>
4.121	<u>Officer's Certificate establishing the terms of Sierra Pacific Power Company's General and Refunding Mortgage Notes, Series V (Nos. V-1, V-2 and V-3) (incorporated by reference to Exhibit 4.4 to the Sierra Pacific Power Company Current Report on Form 8-K dated May 24, 2016).</u>
4.122	<u>Officer's Certificate establishing the terms of Sierra Pacific Power Company's 4.71% General and Refunding Mortgage Bonds, Series W, due 2052 (incorporated by reference to Exhibit 4.3 to the Sierra Pacific Power Company Current Report on Form 8-K dated June 3, 2022).</u>
4.123	<u>Bond Purchase Agreement, dated as of May 31, 2022, by and among Sierra Pacific Power Company and the Purchasers, relating to the \$250,000,000 in principal amount of the 4.71% General and Refunding Mortgage Bonds due 2052 (incorporated by reference to Exhibit 4.1 to the Sierra Pacific Power Company Current Report on Form 8-K dated June 3, 2022).</u>
4.124	<u>Officer's Certificate establishing the terms of Sierra Pacific Power Company's 5.900% General and Refunding Mortgage Bonds, Series 2023A, due 2054 (incorporated by reference to Exhibit 4.1 to the Sierra Pacific Power Company Current Report on Form 8-K dated September 18, 2023).</u>
10.19	<u>Second Amendment to the \$400,000,000 Fifth Amended and Restated Credit Agreement, dated as of June 28, 2024, among Sierra Pacific Power Company, as Borrower, the Banks, Financial Institutions and Other Institutional Lenders, as Initial Lenders, Wells Fargo Bank, National Association, as Administrative Agent and the LC Issuing Banks (incorporated by reference to Exhibit 10.8 to the Sierra Pacific Power Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2024).</u>

EASTERN ENERGY GAS

3.14	<u>Articles of Organization of Dominion Energy Gas Holdings, LLC (incorporated by reference to Exhibit 3.1 to the Dominion Energy Gas Holdings, LLC Form S-4 dated April 4, 2014).</u>
3.15	<u>Articles of Amendment to the Articles of Organization of Eastern Energy Gas Holdings, LLC (incorporated by reference to Exhibit 3.1 to the Eastern Energy Gas Holdings, LLC Current Report on Form 8-K dated November 2, 2020).</u>

<u>Exhibit No.</u>	<u>Description</u>
3.16	<u>Operating Agreement of Eastern Energy Gas Holdings, LLC, as amended and restated, effective November 2, 2020 (incorporated by reference to Exhibit 3.2 to the Eastern Energy Gas Holdings, LLC Current Report on Form 8-K dated November 2, 2020).</u>
10.20	<u>Distribution and Assumption Agreement (incorporated by reference to Exhibit 10.1 to the Eastern Energy Gas Holdings, LLC Current Report on Form 8-K dated November 2, 2020).</u>
10.21	<u>Distribution, Contribution and Assumption Agreement (incorporated by reference to Exhibit 10.2 to the Eastern Energy Gas Holdings, LLC Current Report on Form 8-K dated November 2, 2020).</u>
10.22	<u>Amended and Restated \$400,000,000 Inter-Company Credit Agreement, dated as of March 1, 2023, by and between BHE GT&S, LLC and Eastern Energy Gas Holdings, LLC (incorporated by reference to Exhibit 10.4 to the Eastern Energy Gas Holdings, LLC Quarterly Report on Form 10-Q for the quarter ended March 31, 2023).</u>
10.23	<u>Amended and Restated \$650,000,000 Inter-Company Credit Agreement, dated as of November 15, 2022, by and between BHE GT&S, LLC and Eastern Energy Gas Holdings, LLC (incorporated by reference to Exhibit 10.37 to the Eastern Energy Gas Holdings, LLC Annual Report on Form 10-K for the year ended December 31, 2023).</u>
23.5	<u>Consent of Deloitte & Touche LLP.</u>
31.13	<u>Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.</u>
31.14	<u>Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.</u>
32.13	<u>Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.</u>
32.14	<u>Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.</u>

BERKSHIRE HATHAWAY ENERGY AND EASTERN ENERGY GAS

4.125	<u>Indenture, dated as of October 1, 2013, by and between Dominion Energy Gas Holdings, LLC and Deutsche Bank Trust Company Americas, Trustee (incorporated by reference to Exhibit 4.1, Form S-4, File No. 333-195066 dated April 4, 2014).</u>
4.126	<u>Third Supplemental Indenture, dated as of October 1, 2013, by and between Dominion Energy Gas Holdings, LLC and Deutsche Bank Trust Company Americas, Trustee, relating to the 4.80% Senior Notes due 2043 (incorporated by reference to Exhibit 4.4, Form S-4, File No. 333-195066, dated April 4, 2014).</u>
4.127	<u>Sixth Supplemental Indenture, dated as of December 1, 2014, by and between Dominion Energy Gas Holdings, LLC and Deutsche Bank Trust Company Americas, Trustee, relating to the 4.60% Senior Notes due 2044 (incorporated by reference to Exhibit 4.4 to the Eastern Energy Gas Holdings, LLC Current Report on Form 8-K dated December 8, 2014).</u>
4.128	<u>Eighth Supplemental Indenture, dated as of May 1, 2016, by and between Dominion Energy Gas Holdings, LLC and Deutsche Bank Trust Company Americas, Trustee, relating to the 3.80% Senior Notes due 2031 (incorporated by reference to Exhibit 4.1.a to the Eastern Energy Gas Holdings, LLC Quarterly Report on Form 10-Q for the quarter ended June 30, 2016).</u>
4.129	<u>Ninth Supplemental Indenture, dated as of June 1, 2016, by and between Dominion Energy Gas Holdings, LLC and Deutsche Bank Trust Company Americas, Trustee, relating to the 1.45% Senior Notes due 2026 (incorporated by reference to Exhibit 4.1.b to the Eastern Energy Gas Holdings, LLC Quarterly Report on Form 10-Q for the quarter ended June 30, 2016).</u>
4.130	<u>Thirteenth Supplemental Indenture, dated November 1, 2019, by and between Dominion Energy Gas Holdings, LLC and Deutsche Bank Trust Company Americas, Trustee, relating to the 3.00% Senior Notes due 2029 (incorporated by reference to Exhibit 4.3 to the Eastern Energy Gas Holdings, LLC Current Report on Form 8-K dated November 21, 2019).</u>
4.131	<u>Fourteenth Supplemental Indenture, dated November 1, 2019, by and between Dominion Energy Gas Holdings, LLC and Deutsche Bank Trust Company Americas, Trustee, relating to the 3.90% Senior Notes due 2049 (incorporated by reference to Exhibit 4.4 to the Eastern Energy Gas Holdings, LLC Current Report on Form 8-K dated November 21, 2019).</u>
4.132	<u>Fifteenth Supplemental Indenture, dated as of June 30, 2021, by and between Eastern Energy Gas Holdings, LLC and Deutsche Bank Trust Company Americas, as trustee, to the Indenture dated as of October 1, 2013, by and between Eastern Energy Gas Holdings, LLC and Deutsche Bank Trust Company Americas (incorporated by reference to Exhibit 4.1 to the Eastern Energy Gas Holdings, LLC Current Report on Form 8-K dated July 1, 2021).</u>

<u>Exhibit No.</u>	<u>Description</u>
4.133	<u>Sixteenth Supplemental Indenture, dated as of October 9, 2024, by and between Eastern Energy Gas Holdings, LLC and Deutsche Bank Trust Company Americas, as trustee, to the Indenture dated as of October 1, 2013, by and between Eastern Energy Gas Holdings, LLC and Deutsche Bank Trust Company Americas (incorporated by reference to Exhibit 4.2 to the Eastern Energy Gas Holdings, LLC Current Report on Form 8-K dated October 9, 2024).</u>
4.134	<u>Seventeenth Supplemental Indenture, dated January 15, 2025, by and between Eastern Energy Gas Holdings, LLC and Deutsche Bank Trust Company, LLC and Deutsche Bank Trust Company Americas, as trustee, to the Indenture dated as of October 1, 2013, by and between Eastern Energy Gas Holdings, LLC and Deutsche Bank Trust Company Americas (incorporated by reference to Exhibit 4.2 to the Eastern Energy Gas Holdings, LLC Current Report on Form 8-K dated January 15, 2025).</u>
4.135	<u>Eighteenth Supplemental Indenture, dated January 15, 2025, by and between Eastern Energy Gas Holdings, LLC and Deutsche Bank Trust Company, LLC and Deutsche Bank Trust Company Americas, as trustee, to the Indenture dated as of October 1, 2013, by and between Eastern Energy Gas Holdings, LLC and Deutsche Bank Trust Company Americas (incorporated by reference to Exhibit 4.3 to the Eastern Energy Gas Holdings, LLC Current Report on Form 8-K dated January 15, 2025).</u>
4.136	<u>Description of Dominion Energy Gas Holdings, LLC's 4.60% Series C Senior Notes due 2044 (incorporated by reference to Exhibit 4.21 to the Dominion Energy Gas Holdings, LLC Annual Report on Form 10-K for the year ended December 31, 2019).</u>

EASTERN GAS TRANSMISSION AND STORAGE

3.17	<u>Certificate of Incorporation of Consolidated Gas Transmission Corporation (incorporated by reference to Exhibit 3.1, Form S-4, File No. 333-266049 dated July 25, 2022).</u>
3.18	<u>Bylaws of Dominion Energy Transmission, Inc. (incorporated by reference to Exhibit 3.2, Form S-4, File No. 333-266049 dated July 25, 2022).</u>
10.24	<u>Amended and Restated \$400,000,000 Inter-Company Credit Agreement, dated as of March 1, 2023, by and between Eastern Energy Gas Holdings, LLC and Eastern Gas Transmission and Storage, Inc. (incorporated by reference to Exhibit 10.5 to the Eastern Gas Transmission and Storage, Inc. Quarterly Report on Form 10-Q for the quarter ended March 31, 2023).</u>
10.25	<u>Amended and Restated \$400,000,000 Inter-Company Credit Agreement, dated as of March 1, 2023, by and between Eastern Gas Transmission and Storage, Inc. and Eastern Energy Gas Holdings, LLC (incorporated by reference to Exhibit 10.6 to the Eastern Gas Transmission and Storage Inc. Quarterly Report on Form 10-Q for the quarter ended March 31, 2023).</u>
31.15	<u>Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.</u>
31.16	<u>Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.</u>
32.15	<u>Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.</u>
32.16	<u>Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.</u>

BERKSHIRE HATHAWAY ENERGY AND EASTERN GAS TRANSMISSION AND STORAGE

4.137	<u>Indenture, dated as of June 30, 2021, by and between Eastern Gas Transmission and Storage, Inc. and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated by reference to Exhibit 4.6 to the Eastern Energy Gas Holdings, LLC Quarterly Report on Form 10-Q for the quarter ended June 30, 2021).</u>
4.138	<u>First Supplemental Indenture, dated as of June 30, 2021, by and between Eastern Gas Transmission and Storage, Inc. and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of June 30, 2021, and relating to the 3.900% Senior Notes due 2049 (incorporated by reference to Exhibit 4.7 to the Eastern Energy Gas Holdings, LLC Quarterly Report on Form 10-Q for the quarter ended June 30, 2021).</u>
4.139	<u>Second Supplemental Indenture, dated as of June 30, 2021, by and between Eastern Gas Transmission and Storage, Inc. and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of June 30, 2021, and relating to the 4.600% Senior Notes due 2044 (incorporated by reference to Exhibit 4.8 to the Eastern Energy Gas Holdings, LLC Quarterly Report on Form 10-Q for the quarter ended June 30, 2021).</u>
4.140	<u>Third Supplemental Indenture, dated as of June 30, 2021, by and between Eastern Gas Transmission and Storage, Inc. and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of June 30, 2021, and relating to the 4.800% Senior Notes due 2043 (incorporated by reference to Exhibit 4.9 to the Eastern Energy Gas Holdings, LLC Quarterly Report on Form 10-Q for the quarter ended June 30, 2021).</u>

<u>Exhibit No.</u>	<u>Description</u>
4.141	<u>Fourth Supplemental Indenture, dated as of June 30, 2021, by and between Eastern Gas Transmission and Storage, Inc. and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of June 30, 2021, and relating to the 3.000% Senior Notes due 2029 (incorporated by reference to Exhibit 4.10 to the Eastern Energy Gas Holdings, LLC Quarterly Report on Form 10-Q for the quarter ended June 30, 2021).</u>
4.142	<u>Sixth Supplemental Indenture, dated as of December 10, 2024, by and between Eastern Gas Transmission and Storage, Inc. and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of June 30, 2021, and relating to the 5.020% Senior Notes due 2034 (incorporated by reference to Exhibit 4.2 to the Eastern Gas Transmission and Storage, Inc. Current Report on Form 8-K dated December 10, 2024).</u>

ALL REGISTRANTS

101	The following financial information from each respective Registrant's Annual Report on Form 10-K for the year ended December 31, 2024 is formatted in iXBRL (Inline eXtensible Business Reporting Language) and included herein: (i) the Consolidated Balance Sheets, (ii) the Consolidated Statements of Operations, (iii) the Consolidated Statements of Comprehensive Income, (iv) the Consolidated Statements of Changes in Equity, (v) the Consolidated Statements of Cash Flows and (vi) the Notes to Consolidated Financial Statements, tagged in summary and detail.
104	Cover Page Interactive Data File formatted in iXBRL (Inline eXtensible Business Reporting Language) and contained in Exhibit 101.

(a) Not available electronically on the SEC website as it was filed in paper previous to the electronic system currently in place.

* Management contract or compensatory plan.

Pursuant to Item 601(b)(4)(iii)(A) of Regulation S-K, each Registrant has not filed as an exhibit to this Form 10-K certain instruments with respect to long-term debt not registered in which the total amount of securities authorized thereunder does not exceed 10% of the total assets of the respective Registrant. Each Registrant hereby agrees to furnish a copy of any such instrument to the Commission upon request.

SIGNATURES

BERKSHIRE HATHAWAY ENERGY COMPANY

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 on this 21st day of February 2025.

BERKSHIRE HATHAWAY ENERGY COMPANY

/s/ Scott W. Thon*

Scott W. Thon

Director, President and Chief Executive Officer
(principal executive officer)

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	Date
<u>/s/ Scott W. Thon*</u> Scott W. Thon	Director, President and Chief Executive Officer (principal executive officer)	February 21, 2025
<u>/s/ Charles C. Chang*</u> Charles C. Chang	Senior Vice President and Chief Financial Officer (principal financial and accounting officer)	February 21, 2025
<u>/s/ Gregory E. Abel*</u> Gregory E. Abel	Chair of the Board of Directors	February 21, 2025
<u>/s/ Warren E. Buffett*</u> Warren E. Buffett	Director	February 21, 2025
<u>/s/ Marc D. Hamburg*</u> Marc D. Hamburg	Director	February 21, 2025
<u>*By: /s/ Natalie L. Hocken</u> Natalie L. Hocken	Attorney-in-Fact	February 21, 2025

SIGNATURES

PACIFICORP

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 on this 21st day of February 2025.

PACIFICORP

/s/ Nikki L. Kobliha

Nikki L. Kobliha

Director, Senior Vice President and Chief Financial
Officer
(principal financial and accounting officer)

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.

<u>Signature</u>	<u>Title</u>	<u>Date</u>
<u>/s/ Cindy A. Crane</u> Cindy A. Crane	Chair of the Board of Directors and Chief Executive Officer (principal executive officer)	February 21, 2025
<u>/s/ Nikki L. Kobliha</u> Nikki L. Kobliha	Director, Senior Vice President and Chief Financial Officer (principal financial and accounting officer)	February 21, 2025
<u>/s/ Charles C. Chang</u> Charles C. Chang	Director	February 21, 2025
<u>/s/ Natalie L. Hocken</u> Natalie L. Hocken	Director	February 21, 2025
<u>/s/ Ryan L. Flynn</u> Ryan L. Flynn	Director	February 21, 2025
<u>/s/ Richard J. Garlish</u> Richard J. Garlish	Director	February 21, 2025

SIGNATURES

MIDAMERICAN ENERGY COMPANY

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 on this 21st day of February 2025.

MIDAMERICAN ENERGY COMPANY

/s/ Kelcey A. Brown

Kelcey A. Brown

Director, President and Chief Executive Officer
(principal executive officer)

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 date indicated:

<u>Signature</u>	<u>Title</u>	<u>Date</u>
<u>/s/ Kelcey A. Brown</u> Kelcey A. Brown	Director, President and Chief Executive Officer (principal executive officer)	February 21, 2025
<u>/s/ Blake M. Groen</u> Blake M. Groen	Director, Vice President and Chief Financial Officer (principal financial and accounting officer)	February 21, 2025

SIGNATURES

MIDAMERICAN FUNDING, LLC

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 on this 21st day of February 2025.

MIDAMERICAN FUNDING, LLC

/s/ Kelcey A. Brown

Kelcey A. Brown
Manager and President
(principal executive officer)

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 date indicated:

<u>Signature</u>	<u>Title</u>	<u>Date</u>
<u>/s/ Kelcey A. Brown</u> Kelcey A. Brown	Manager and President (principal executive officer)	February 21, 2025
<u>/s/ Blake M. Groen</u> Blake M. Groen	Vice President and Controller (principal financial and accounting officer)	February 21, 2025
<u>/s/ Daniel S. Fick</u> Daniel S. Fick	Manager	February 21, 2025
<u>/s/ Calvin D. Haack</u> Calvin D. Haack	Manager	February 21, 2025
<u>/s/ Natalie L. Hocken</u> Natalie L. Hocken	Manager	February 21, 2025

SIGNATURES

NEVADA POWER COMPANY

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 on this 21st day of February 2025.

NEVADA POWER COMPANY

/s/ Douglas A. Cannon

Douglas A. Cannon

Director, President and Chief Executive Officer
(principal executive officer)

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 date indicated:

<u>Signature</u>	<u>Title</u>	<u>Date</u>
<u>/s/ Douglas A. Cannon</u> Douglas A. Cannon	Director, President and Chief Executive Officer (principal executive officer)	February 21, 2025
<u>/s/ Michael J. Behrens</u> Michael J. Behrens	Director, Vice President and Chief Financial Officer (principal financial and accounting officer)	February 21, 2025
<u>/s/ Brandon M. Barkhuff</u> Brandon M. Barkhuff	Director	February 21, 2025
<u>/s/ Jennifer L. Oswald</u> Jennifer L. Oswald	Director	February 21, 2025
<u>/s/ Anthony F. Sanchez, III</u> Anthony F. Sanchez, III	Director	February 21, 2025

SIGNATURES

SIERRA PACIFIC POWER COMPANY

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 on this 21st day of February 2025.

SIERRA PACIFIC POWER COMPANY

/s/ Douglas A. Cannon

Douglas A. Cannon

Director, President and Chief Executive Officer
(principal executive officer)

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 date indicated:

<u>Signature</u>	<u>Title</u>	<u>Date</u>
<u>/s/ Douglas A. Cannon</u> Douglas A. Cannon	Director, President and Chief Executive Officer (principal executive officer)	February 21, 2025
<u>/s/ Michael J. Behrens</u> Michael J. Behrens	Vice President and Chief Financial Officer (principal financial and accounting officer)	February 21, 2025
<u>/s/ Brandon M. Barkhuff</u> Brandon M. Barkhuff	Director	February 21, 2025
<u>/s/ Jesse E. Murray</u> Jesse E. Murray	Director	February 21, 2025
<u>/s/ Jennifer L. Oswald</u> Jennifer L. Oswald	Director	February 21, 2025
<u>/s/ Anthony F. Sanchez, III</u> Anthony F. Sanchez, III	Director	February 21, 2025

SIGNATURES

EASTERN ENERGY GAS HOLDINGS, LLC

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 on this 21st day of February 2025.

EASTERN ENERGY GAS HOLDINGS, LLC

/s/ Paul E. Ruppert

Paul E. Ruppert

President and Chief Executive Officer
(principal executive officer)

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 date indicated:

<u>Signature</u>	<u>Title</u>	<u>Date</u>
<u>/s/ Paul E. Ruppert</u> Paul E. Ruppert	President and Chief Executive Officer (principal executive officer)	February 21, 2025
<u>/s/ Scott C. Miller</u> Scott C. Miller	Vice President, Chief Financial Officer and Treasurer (principal financial and accounting officer)	February 21, 2025
<u>/s/ Mark A. Hewett</u> Mark A. Hewett	Manager	February 21, 2025
<u>/s/ Calvin D. Haack</u> Calvin D. Haack	Manager	February 21, 2025
<u>/s/ Natalie L. Hocken</u> Natalie L. Hocken	Manager	February 21, 2025

SIGNATURES

EASTERN GAS TRANSMISSION AND STORAGE, INC.

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 on this 21st day of February 2025.

EASTERN GAS TRANSMISSION AND STORAGE, INC.

/s/ Paul E. Ruppert

Paul E. Ruppert

Chair of the Board of Directors and President
(principal executive officer)

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 date indicated:

<u>Signature</u>	<u>Title</u>	<u>Date</u>
<u>/s/ Paul E. Ruppert</u> Paul E. Ruppert	Chair of the Board of Directors and President (principal executive officer)	February 21, 2025
<u>/s/ Scott C. Miller</u> Scott C. Miller	Director, Vice President, Chief Financial Officer and Treasurer (principal financial and accounting officer)	February 21, 2025
<u>/s/ Anne E. Bomar</u> Anne E. Bomar	Director	February 21, 2025

**SUPPLEMENTAL INFORMATION TO BE FURNISHED WITH REPORTS FILED PURSUANT TO
SECTION 15(D) OF THE ACT BY REGISTRANTS WHICH HAVE NOT REGISTERED SECURITIES PURSUANT
TO SECTION 12 OF THE ACT**

No annual report to security holders covering each respective Registrant's last fiscal year or proxy material has been sent to security holders.

**BERKSHIRE HATHAWAY ENERGY COMPANY
SUBSIDIARIES AND JOINT VENTURES**

Pursuant to Item 601(b)(21)(ii) of Regulation S-K, we have omitted certain subsidiaries (all of which, when considered in the aggregate as a single subsidiary, would not constitute a significant subsidiary as of the end of our last fiscal year).

PPW Holdings LLC	Delaware
PacifiCorp	Oregon
MidAmerican Funding, LLC	Iowa
MHC Inc.	Iowa
MidAmerican Energy Company	Iowa
NVE Holdings, LLC	Delaware
NV Energy, Inc.	Nevada
Nevada Power Company	Nevada
Sierra Pacific Power Company	Nevada
Northern Powergrid Holdings Company	United Kingdom
Northern Powergrid UK Holdings	United Kingdom
Northern Electric plc.	United Kingdom
Yorkshire Electricity Group plc.	United Kingdom
Northern Powergrid (Yorkshire) plc.	United Kingdom
BHE Pipeline Group, LLC	Delaware
BHE GT&S, LLC	Delaware
Eastern Energy Gas Holdings, LLC	Virginia
Eastern MLP Holding Company II, LLC	Virginia
Cove Point GP Holding Company, LLC	Delaware
Cove Point LNG, LP	Delaware
Eastern Gas Transmission and Storage, Inc.	Delaware
NNGC Acquisition, LLC	Delaware
Northern Natural Gas Company	Delaware
BHE Canada Holdings Corporation	Canada
BHE U.S. Transmission, LLC	Delaware
BHE Renewables, LLC	Delaware
HomeServices of America, Inc.	Delaware
Western Capital Group, LLC	Nevada

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-276321 on Form S-8 of our report dated February 21, 2025, relating to the financial statements and financial statement schedule of Berkshire Hathaway Energy Company appearing in this Annual Report on Form 10-K for the year ended December 31, 2024.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
February 21, 2025

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-281019 on Form S-3 of our report dated February 21, 2025, relating to the financial statements of PacifiCorp appearing in this Annual Report on Form 10-K for the year ended December 31, 2024.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 21, 2025

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-257069 on Form S-3 of our report dated February 21, 2025, relating to the financial statements of MidAmerican Energy Company appearing in this Annual Report on Form 10-K for the year ended December 31, 2024.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
February 21, 2025

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-267865 on Form S-3 of our report dated February 21, 2025, relating to the financial statements of Nevada Power Company appearing in this Annual Report on Form 10-K for the year ended December 31, 2024.

/s/ Deloitte & Touche LLP

Las Vegas, Nevada
February 21, 2025

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-276072 on Form S-3 of our report dated February 21, 2025, relating to the financial statements of Eastern Energy Gas Holdings, LLC appearing in this Annual Report on Form 10-K for the year ended December 31, 2024.

/s/ Deloitte & Touche LLP

Richmond, Virginia
February 21, 2025

POWER OF ATTORNEY

The undersigned, a member of the Board of Directors or an officer of BERKSHIRE HATHAWAY ENERGY COMPANY, an Iowa corporation (the "Company"), hereby constitutes and appoints Natalie L. Hocken and Jeffery B. Erb and each of them, as his/her true and lawful attorney-in-fact and agent, with full power of substitution and resubstitution, for and in his/her stead, in any and all capacities, to sign on his/her behalf the Company's Annual Report on Form 10-K for the fiscal year ending December 31, 2024 and to execute any amendments thereto and to file the same, with all exhibits thereto, and all other documents in connection therewith, with the Securities and Exchange Commission and applicable stock exchanges, with the full power and authority to do and perform each and every act and thing necessary or advisable to all intents and purposes as he/she might or could do in person, hereby ratifying and confirming all that said attorney-in-fact and agent, or his/her substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

Executed as of February 21, 2025

/s/ Scott W. Thon

SCOTT W. THON

/s/ Charles C. Chang

CHARLES C. CHANG

/s/ Gregory E. Abel

GREGORY E. ABEL

/s/ Warren E. Buffett

WARREN E. BUFFETT

/s/ Marc D. Hamburg

MARC D. HAMBURG

**CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002**

I, Scott W. Thon, certify that:

1. I have reviewed this Annual Report on Form 10-K of Berkshire Hathaway Energy Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
 - (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2025

/s/ Scott W. Thon

Scott W. Thon

President and Chief Executive Officer
(principal executive officer)

**CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002**

I, Charles C. Chang, certify that:

1. I have reviewed this Annual Report on Form 10-K of Berkshire Hathaway Energy Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
 - (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2025

/s/ Charles C. Chang

Charles C. Chang

Senior Vice President and Chief Financial Officer
(principal financial officer)

**CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002**

I, Cindy A. Crane, certify that:

1. I have reviewed this Annual Report on Form 10-K of PacifiCorp;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
 - (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2025

/s/ Cindy A. Crane

Cindy A. Crane

Chair of the Board of Directors and Chief Executive
Officer

(principal executive officer)

**CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002**

I, Nikki L. Kobliha, certify that:

1. I have reviewed this Annual Report on Form 10-K of PacifiCorp;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
 - (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2025

/s/ Nikki L. Kobliha

Nikki L. Kobliha

Senior Vice President and Chief Financial Officer
(principal financial officer)

**CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002**

I, Kelcey A. Brown, certify that:

1. I have reviewed this Annual Report on Form 10-K of MidAmerican Energy Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
 - (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2025

/s/ Kelcey A. Brown

Kelcey A. Brown

President and Chief Executive Officer

(principal executive officer)

**CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002**

I, Blake M. Groen, certify that:

1. I have reviewed this Annual Report on Form 10-K of MidAmerican Energy Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
 - (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2025

/s/ Blake M. Groen

Blake M. Groen

Vice President and Chief Financial Officer
(principal financial officer)

**CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002**

I, Kelcey A. Brown, certify that:

1. I have reviewed this Annual Report on Form 10-K of MidAmerican Funding, LLC;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
 - (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2025

/s/ Kelcey A. Brown
Kelcey A. Brown
President
(principal executive officer)

**CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002**

I, Blake M. Groen, certify that:

1. I have reviewed this Annual Report on Form 10-K of MidAmerican Funding, LLC;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
 - (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2025

/s/ Blake M. Groen

Blake M. Groen

Vice President and Controller
(principal financial officer)

**CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002**

I, Douglas A. Cannon, certify that:

1. I have reviewed this Annual Report on Form 10-K of Nevada Power Company and its subsidiaries (dba NV Energy);
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
 - (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2025

/s/ Douglas A. Cannon

Douglas A. Cannon

President and Chief Executive Officer

(principal executive officer)

**CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002**

I, Michael J. Behrens, certify that:

1. I have reviewed this Annual Report on Form 10-K of Nevada Power Company and its subsidiaries (dba NV Energy);
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
 - (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2025

/s/ Michael J. Behrens

Michael J. Behrens

Vice President and Chief Financial Officer
(principal financial officer)

**CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002**

I, Douglas A. Cannon, certify that:

1. I have reviewed this Annual Report on Form 10-K of Sierra Pacific Power Company and its subsidiaries (dba NV Energy);
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
 - (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2025

/s/ Douglas A. Cannon

Douglas A. Cannon

President and Chief Executive Officer

(principal executive officer)

**CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002**

I, Michael J. Behrens, certify that:

1. I have reviewed this Annual Report on Form 10-K of Sierra Pacific Power Company and its subsidiaries (dba NV Energy);
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
 - (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2025

/s/ Michael J. Behrens

Michael J. Behrens

Vice President and Chief Financial Officer
(principal financial officer)

**CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002**

I, Paul E. Ruppert, certify that:

1. I have reviewed this Annual Report on Form 10-K of Eastern Energy Gas Holdings, LLC;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
 - (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2025

/s/ Paul E. Ruppert

Paul E. Ruppert

President and Chief Executive Officer

(principal executive officer)

**CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002**

I, Scott C. Miller, certify that:

1. I have reviewed this Annual Report on Form 10-K of Eastern Energy Gas Holdings, LLC;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
 - (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2025

/s/ Scott C. Miller

Scott C. Miller

Vice President, Chief Financial Officer and Treasurer
(principal financial officer)

**CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002**

I, Paul E. Ruppert, certify that:

1. I have reviewed this Annual Report on Form 10-K of Eastern Gas Transmission and Storage, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - (b) [Reserved];
 - (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2025

/s/ Paul E. Ruppert

Paul E. Ruppert

Chair of the Board of Directors and President
(principal executive officer)

**CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002**

I, Scott C. Miller, certify that:

1. I have reviewed this Annual Report on Form 10-K of Eastern Gas Transmission and Storage, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - (b) [Reserved];
 - (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2025

/s/ Scott C. Miller

Scott C. Miller

Director, Vice President, Chief Financial Officer and Treasurer
(principal financial officer)

**CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002**

I, Scott W. Thon, President and Chief Executive Officer of Berkshire Hathaway Energy Company (the "Company"), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

- (1) the Annual Report on Form 10-K of the Company for the annual period ended December 31, 2024 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and
- (2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 21, 2025

/s/ Scott W. Thon

Scott W. Thon

President and Chief Executive Officer
(principal executive officer)

**CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002**

I, Charles C. Chang, Senior Vice President and Chief Financial Officer of Berkshire Hathaway Energy Company (the "Company"), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

- (1) the Annual Report on Form 10-K of the Company for the annual period ended December 31, 2024 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and
- (2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 21, 2025

/s/ Charles C. Chang

Charles C. Chang

Senior Vice President and Chief Financial Officer
(principal financial officer)

**CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002**

I, Cindy A. Crane, Chair of the Board of Directors and Chief Executive Officer of PacifiCorp, certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

- (1) the Annual Report on Form 10-K of PacifiCorp for the annual period ended December 31, 2024 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and
- (2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PacifiCorp.

Date: February 21, 2025

/s/ Cindy A. Crane

Cindy A. Crane
Chair of the Board of Directors and Chief Executive
Officer
(principal executive officer)

**CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002**

I, Nikki L. Kobliha, Senior Vice President and Chief Financial Officer of PacifiCorp, certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

- (1) the Annual Report on Form 10-K of PacifiCorp for the annual period ended December 31, 2024 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and
- (2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PacifiCorp.

Date: February 21, 2025

/s/ Nikki L. Kobliha

Nikki L. Kobliha

Senior Vice President and Chief Financial Officer
(principal financial officer)

**CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002**

I, Kelcey A. Brown, President and Chief Executive Officer of MidAmerican Energy Company, certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

- (1) the Annual Report on Form 10-K of MidAmerican Energy Company for the annual period ended December 31, 2024 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and
- (2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of MidAmerican Energy Company.

Date: February 21, 2025

/s/ Kelcey A. Brown

Kelcey A. Brown

President and Chief Executive Officer

(principal executive officer)

**CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002**

I, Blake M. Groen, Vice President and Chief Financial Officer of MidAmerican Energy Company, certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

- (1) the Annual Report on Form 10-K of MidAmerican Energy Company for the annual period ended December 31, 2024 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and
- (2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of MidAmerican Energy Company.

Date: February 21, 2025

/s/ Blake M. Groen

Blake M. Groen

Vice President and Chief Financial Officer
(principal financial officer)

**CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002**

I, Kelcey A. Brown, President of MidAmerican Funding, LLC, certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

- (1) the Annual Report on Form 10-K of MidAmerican Funding, LLC for the annual period ended December 31, 2024 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and
- (2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of MidAmerican Funding, LLC.

Date: February 21, 2025

/s/ Kelcey A. Brown
Kelcey A. Brown
President
(principal executive officer)

**CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002**

I, Blake M. Groen, Vice President and Controller of MidAmerican Funding, LLC, certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

- (1) the Annual Report on Form 10-K of MidAmerican Funding, LLC for the annual period ended December 31, 2024 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and
- (2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of MidAmerican Funding, LLC.

Date: February 21, 2025

/s/ Blake M. Groen

Blake M. Groen

Vice President and Controller

(principal financial officer)

**CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002**

I, Douglas A. Cannon, President and Chief Executive Officer of Nevada Power Company and its subsidiaries (dba NV Energy), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

- (1) the Annual Report on Form 10-K of Nevada Power Company and its subsidiaries for the annual period ended December 31, 2024 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and
- (2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Nevada Power Company and its subsidiaries.

Date: February 21, 2025

/s/ Douglas A. Cannon
Douglas A. Cannon
President and Chief Executive Officer
(principal executive officer)

**CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002**

I, Michael J. Behrens, Vice President and Chief Financial Officer of Nevada Power Company and its subsidiaries (dba NV Energy), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

- (1) the Annual Report on Form 10-K of Nevada Power Company and its subsidiaries for the annual period ended December 31, 2024 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and
- (2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Nevada Power Company and its subsidiaries.

Date: February 21, 2025

/s/ Michael J. Behrens

Michael J. Behrens

Vice President and Chief Financial Officer
(principal financial officer)

**CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002**

I, Douglas A. Cannon, President and Chief Executive Officer of Sierra Pacific Power Company and its subsidiaries (dba NV Energy), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

- (1) the Annual Report on Form 10-K of Sierra Pacific Power Company and its subsidiaries for the annual period ended December 31, 2024 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and
- (2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Sierra Pacific Power Company and its subsidiaries.

Date: February 21, 2025

/s/ Douglas A. Cannon
Douglas A. Cannon
President and Chief Executive Officer
(principal executive officer)

**CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002**

I, Michael J. Behrens, Vice President and Chief Financial Officer of Sierra Pacific Power Company and its subsidiaries (dba NV Energy), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

- (1) the Annual Report on Form 10-K of Sierra Pacific Power Company and its subsidiaries for the annual period ended December 31, 2024 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and
- (2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Sierra Pacific Power Company and its subsidiaries.

Date: February 21, 2025

/s/ Michael J. Behrens

Michael J. Behrens

Vice President and Chief Financial Officer
(principal financial officer)

**CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002**

I, Paul E. Ruppert, President and Chief Executive Officer of Eastern Energy Gas Holdings, LLC, certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

- (1) the Annual Report on Form 10-K of Eastern Energy Gas Holdings, LLC for the annual period ended December 31, 2022 (the "Report") fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and
- (2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of Eastern Energy Gas Holdings, LLC.

Date: February 21, 2025

/s/ Paul E. Ruppert

Paul E. Ruppert
President and Chief Executive Officer
(principal executive officer)

**CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002**

I, Scott C. Miller, Vice President, Chief Financial Officer and Treasurer of Eastern Energy Gas Holdings, LLC, certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

- (1) the Annual Report on Form 10-K of Eastern Energy Gas Holdings, LLC for the annual period ended December 31, 2022 (the "Report") fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and
- (2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of Eastern Energy Gas Holdings, LLC.

Date: February 21, 2025

/s/ Scott C. Miller

Scott C. Miller

Vice President, Chief Financial Officer and Treasurer
(principal financial officer)

**CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002**

I, Paul E. Ruppert, Chair of the Board of Directors and President of Eastern Gas Transmission and Storage, Inc., certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

- (1) the Annual Report on Form 10-K of Eastern Gas Transmission and Storage, Inc. for the annual period ended December 31, 2022 (the "Report") fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and
- (2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of Eastern Gas Transmission and Storage, Inc..

Date: February 21, 2025

/s/ Paul E. Ruppert

Paul E. Ruppert
Chair of the Board of Directors and President
(principal executive officer)

**CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002**

I, Scott C. Miller, Vice President, Chief Financial Officer and Treasurer of Eastern Gas Transmission and Storage, Inc., certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

- (1) the Annual Report on Form 10-K of Eastern Gas Transmission and Storage, Inc. for the annual period ended December 31, 2022 (the "Report") fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and
- (2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of Eastern Gas Transmission and Storage, Inc..

Date: February 21, 2025

/s/ Scott C. Miller

Scott C. Miller

Director, Vice President, Chief Financial Officer and Treasurer
(principal financial officer)

**MINE SAFETY VIOLATIONS AND OTHER LEGAL MATTER DISCLOSURES
PURSUANT TO SECTION 1503(a) OF THE DODD-FRANK WALL STREET
REFORM AND CONSUMER PROTECTION ACT**

PacifiCorp and its subsidiaries operate certain coal mines and coal processing facilities (collectively, the "mining facilities") that are regulated by the Federal Mine Safety and Health Administration ("MSHA") under the Federal Mine Safety and Health Act of 1977 (the "Mine Safety Act"). MSHA inspects PacifiCorp's mining facilities on a regular basis. The total number of reportable Mine Safety Act citations, orders, assessments and legal actions for the year ended December 31, 2024 are summarized in the table below and are subject to contest and appeal. The severity and assessment of penalties may be reduced or, in some cases, dismissed through the contest and appeal process. Amounts are reported regardless of whether PacifiCorp has challenged or appealed the matter. Mines that are closed or idled that had no reportable events occurring at those locations during the year ended December 31, 2024 are not included in the information below. There were no mining-related fatalities during the year ended December 31, 2024. PacifiCorp has not received any notice of a pattern, or notice of the potential to have a pattern, of violations of mandatory health or safety standards that are of such nature as could have significantly and substantially contributed to the cause and effect of coal or other mine health or safety hazards under Section 104(e) of the Mine Safety Act during the year ended December 31, 2024.

Mining Facilities	Mine Safety Act					Total Value of Proposed MSHA Assessments (in thousands)	Legal Actions		
	Section 104 Significant and Substantial Citations ⁽¹⁾	Section 104(b) Orders ⁽²⁾	Section 104(d) Citations/ Orders ⁽³⁾	Section 110(b)(2) Violations ⁽⁴⁾	Section 107(a) Imminent Danger Orders ⁽⁵⁾		Pending as of Last Day of Period ⁽⁶⁾	Instituted During Period	Resolved During Period
Bridger (surface)	—	—	—	—	—	\$ —	—	—	—
Wyodak Coal Crushing Facility	—	—	—	—	—	—	—	—	—

- (1) Citations for alleged violations of mandatory health and safety standards that could significantly or substantially contribute to the cause and effect of a safety or health hazard under Section 104 of the Mine Safety Act.
- (2) For alleged failure to totally abate the subject matter of a Mine Safety Act Section 104(a) citation within the period specified in the citation.
- (3) For alleged unwarrantable failure (i.e., aggravated conduct constituting more than ordinary negligence) to comply with a mandatory health or safety standard.
- (4) For alleged flagrant violations (i.e., reckless or repeated failure to make reasonable efforts to eliminate a known violation of a mandatory health or safety standard that substantially and proximately caused, or reasonably could have been expected to cause, death or serious bodily injury).
- (5) For the existence of any condition or practice in a coal or other mine which could reasonably be expected to cause death or serious physical harm before such condition or practice can be abated.
- (6) For the existence of any proposed penalties under Subparts B-H of the Federal Mine Safety and Health Review Commission's procedural rules. The pending legal actions are not exclusive to citations, notices, orders and penalties assessed by the MSHA during the reporting period.