MIDAMERICAN ENERGY COMPANY
Obsessively, Relentlessly At Your Service™

CON 12-1-1
Doc # 109763

March 28, 2024

Mr. Chad A. Stobbe
Iowa Department of Natural Resources
Wallace State Office Building
502 East 9th Street
Des Moines, IA 50319

Re: MidAmerican Energy Company Coal Combustion Residue ("CCR") Monofills and Impoundments; Permits: #78-SDP-26-06P, #97-SDP-12-95P, #97-SDP-13-98P, #97-SDP-24-20C, #70-SDP-16-04P, #70-SDP-17-04C, #97-SDP-22-16C, #78-SDP-33-16C, #70-SDP-23-18C; Financial assurance Iowa Administrative Code 567 Chapter 103.3(6)"e" Corporate financial test

Dear Mr. Stobbe:

This letter is in support of MidAmerican Energy Company (MidAmerican Energy) using the corporate financial test to demonstrate financial assurance for closure and post-closure costs as specified in Iowa Administrative Code ("IAC") 567 Chapter 103.3(6)"e"(2)"1" and granted by the rule variance request approved by the Iowa Department of Natural Resources in a letter dated September 12, 2008 (copy enclosed).

MidAmerican Energy is the owner and operator of the following CCR monofills and inactive surface impoundments for which the combined financial assurance for closure and post-closure work is demonstrated through the substantive requirements of the financial component IAC 567 Chapter 103.3(6)"e"(1):

Walter Scott Jr. Energy Center (WSEC)
#78-SDP-26-06P
Council Bluffs, Iowa

Louisa Generating Station (LGS) – East
#70-SDP-16-04P
Muscatine, Iowa

Louisa Generating Station (LGS) – West
#70-SDP-17-04C
Muscatine, Iowa

George Neal Energy Center North (Neal North) – Closed #97-SDP-24-20C
Sergeant Bluff, Iowa

George Neal Energy Center – North (Neal North)
#97-SDP-12-95P
Sergeant Bluff, Iowa

George Neal Energy Center – South (Neal South)
#97-SDP-13-98P
Salix, Iowa

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George Neal Energy Center – North
(Neal North Imp. 1, 2, 3A, 3B) #97-SDP-22-16C
Sergeant Bluff, Iowa

Walter Scott Jr. Energy Center (WSEC)
(WSEC North and South Ponds) #78-SDP-33-16C
Council Bluffs, Iowa

Louisa Generating Station (LGS)
(Bottom Ash Pond) #70-SDP-23-18C
Muscatine, Iowa

The current estimate for closure and post-closure costs for the six CCR monofill locations and three inactive surface impoundment locations, in accordance with IAC 567 Chapter 103.3(3) and 103.3(4), detailed by the third-party estimate (original copy dated March 7, 2024 enclosed) and covered by the financial test is stated below (in thousands):

Closure costs to be assured	\$25,180
Post-closure costs to be assured	23,295
Total costs to be assured	\$48,475

MidAmerican has the financial ability to complete the work as required in IAC 567 Chapter 103.3(3) and 103.3(4) and meets or exceeds the substantive requirements of the financial component as set out in IAC 567 Chapter 103.3(6)"e"(1):

1.	Current rating of MidAmerican Energy senior unsecured debt and name of rating service:	"A-" Standard and Poor's
2.	Tangible net worth as of December 31, 2023 (SEC Form 10-K):	\$9.603 billion
3.	Assets of MidAmerican Energy located in the United States:	100%

In demonstration of compliance with IAC 567 Chapter 103.3(6)"e"(1) and (2), a copy of MidAmerican Energy's Form 10-K filed with the United States Securities and Exchange Commission for December 31, 2023, is enclosed. MidAmerican Energy's Form 10-K annual filing is independently audited by third-party Certified Public Accountants and provides the financial information that demonstrates MidAmerican Energy's financial capability to complete closure and post-closure obligations for the above referenced CCR monofills.

This financial assurance instrument is intended to cover the 10-year post-closure care period as required in IAC 567-103. MidAmerican Energy understands the federal rules require 30 years of post-closure care and is prepared to provide the financial assurance instrument demonstrating the extended timeframe if the state's rules are amended. For purposes of demonstration, post-closure care costs for both timeframes are provided in the attached closure and post-closure care cost memorandum.

As the chief financial officer for MidAmerican Energy Company, I hereby certify that the information provided in this letter is true to the best of my knowledge and that this letter is being submitted in accordance with Iowa Administrative Code 567 Chapter 103 [subrule 103.3(6)"e"(2)"1"] *Record-keeping and reporting requirements* for the *Corporate financial test.*

Blake Groen
Vice President and Chief Financial Officer

Subscribed and sworn before me by Blake Groen this 28th day of March.

Cory Root
NOTARY PUBLIC IN AND FOR
THE STATE OF IOWA

bcc. Joshua Love
Josh Mohr
Lisa Bircher

CORY ROOT
MY COMMISSION EXPIRES JUNE 30, 2024
COMMISSION NUMBER 832814
NOTARIAL SEAL - IOWA

Fields of Opportunities

STATE OF IOWA

CHESTER J. CULVER, GOVERNOR
PATTY JUDGE, LT. GOVERNOR

DEPARTMENT OF NATURAL RESOURCES
RICHARD A. LEOPOLD, DIRECTOR

September 12, 2008

TOM SPECKETER
VICE PRESIDENT AND CONTROLLER
MIDAMERICAN ENERGY
666 GRAND AVENUE
PO BOX 657
DES MOINES IA 50303-0657

Re: MidAmerican Energy Coal Combustion Residue (CCR) Monofills
Permit #07-SDP-12-95, #97-SDP-13-95, #70-SDP-16-04 and #78-SDP-20-06
Variance Approval: Iowa Administrative Code 567 Chapter 103.3(6)"e"(2)"1"

Dear Mr. Specketer:

This letter is to inform you that the rule variance request from Iowa Administrative Code 567 Chapter 103.3(6)"e"(2)"1" relative to the requirement that permitted CCR monofills submit a letter signed by a certified public accountant, based upon a certified audit that lists all the current cost estimates covered by a financial test and provides evidence demonstrating that the owner or operator meets the conditions of subparagraph 103.3(6)"e"(1), is hereby approved.

This variance is granted based on your April 16, 2008 letter to the department relative to the request to provide proof of financial assurance per a modification to the requirements of the corporate financial test; and that 40 CFR 258.74"e"(2) provides that via the corporate financial test, that an owner or operator's chief financial officer may execute the required letter. By being a rate regulated utility and being publicly traded, it's unlikely that an independent certified public accountant would sign the required letter without performing a full audit. Given that the information and third party certified audit requirements in IAC 567 Chapter 103.3(6)"e"(2) are already covered by MidAmerican Energy's annual Form 10-K filing to the United States Securities and Exchange Commission, a strict application of the rule would be redundant and would not provide any further protection to public health, safety and welfare.

The approved variance is applicable as long as the justification for the request remains the same. If problems arise which would cause MidAmerican Energy to be out of compliance with Iowa Administrative Code 567 Chapter 103, or which would present a risk to public health and the environment, the department may revoke the approval and require MidAmerican Energy comply with the current financial assurance requirements.

Please feel free to contact me with any questions. I can be reached at (515) 242-5951 or Chad.Stobbe@dnr.iowa.gov.

Sincerely,

Chad A. Stobbe

Chad A. Stobbe, Environmental Specialist Senior
Land Quality Bureau

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Cc: IDNR Field Office #3, Spencer, IA
IDNR Field Office #4, Atlantic, IA
IDNR Field Office #6, Washington, IA

11228 Aurora Avenue
Des Moines, Iowa 50322-7905
United States
www.ghd.com

Our reference: 12574984-LTR-07

March 07, 2024

Mr. Josh Mohr
Environmental Director
MidAmerican Energy Company
4299 Northwest Urbandale Drive
Urbandale, Iowa 50322

Coal Combustion Residual Monofills – Closure Cost Estimates for Permitting

Dear Mr. Mohr:

1. Introduction and Certification

GHD prepared this letter and attachments to provide MidAmerican Energy Company (MidAmerican) with cost estimates for closure and post-closure of coal combustion residuals (CCR) Monofills (Monofills) in accordance with the Financial Assurance requirements of Chapter 567—103.3, Iowa Administrative Code (IAC). These cost estimates address the Walter Scott, Jr. Energy Center (WSEC) CCR Monofill in Council Bluffs, Iowa; Louisa Generating Station (LGS) CCR East and West Monofills in Muscatine, Iowa; and three CCR Monofills (Neal North Active, Neal North Closed, and Neal South) at the George Neal Energy Center in Salix, Iowa.

LICENSED PROFESSIONAL ENGINEER MICHAEL J. ALOWITZ 18160 IOWA	**I hereby certify that this engineering document was prepared by me or under my direct personal supervision and that I am a duly licensed Professional Engineer under the laws of the State of Iowa.** Michael J. Alowitz, P.E. 3/7/24 **Date** **License Number:** 18160 **My license renewal date is:** December 31, 2024 **Pages or sheets covered by this seal:** Entire Document

1.1 Estimate Structure

General information about the current and projected conditions at the Monofills is provided in Section 2. Details in this letter are organized to include the components listed in subparagraphs 567—103.3(3)c(6) and 103.3(4)c(6), IAC. For each of the components listed, information is provided in Sections 3 and 4 of this letter to support the estimate.

1.2 Estimate Basis

These cost estimates have been prepared to address closure of the Monofills at the point in the life of each Monofill at which closure would be most expensive. The estimates are to be revised by MidAmerican annually to allow for inflation and other changes in conditions and costs. At the time of a Permit Amendment, the cost estimates are to be revised. The scope of these cost estimates only addresses the areas permitted for CCR disposal as of March 1, 2024. For example, at the LGS East Monofill, only Cells 1 through 3 are permitted for disposal although future cells are planned. These cost estimates have been prepared at the request of MidAmerican and address changes in estimate assumptions since the 2023 estimates were developed.

Earthwork is the largest component of closure costs, specifically the capping of the Monofills; therefore, the most expensive point for closure will coincide with the time at which the most Monofill surface area remains to be capped. This will vary for each Monofill and GHD has estimated this time based on observed fill patterns, known fill rates, previously prepared lifetime estimates, and permitted fill conditions.

GHD has prepared the estimates using several sources of data, including bid information for earthwork projects; verbal prices received from service providers; industry standard values; vendor prices lists; and projections for engineering or design services. The cost estimates are provided in 2024 dollars and are summarized in Table 1; supporting data are provided in Attachment A. Significant variables for future comparison include changing permit requirements and changes to CCR production and recycling rates.

1.3 2024 Updates

This letter updates the cost estimates set forth in the 2023 Memorandum, dated March 7, 2023. The major points of revision are:

- The start date for the cost estimates has been adjusted to March 1, 2024.
- Costs are now in 2023 dollars. An inflation factor of 1.026 has been applied to the unit costs used in the 2023 estimates. This inflation factor is calculated by dividing the 2023 fourth quarter implicit price deflator for gross domestic product by the 2022 fourth quarter value. For the 2023 estimates, this value is 1.026. The data source and calculations are presented in Attachment B in documentation provided by the Iowa Department of Natural Resources (IDNR).
- The number of monitoring wells to plug and abandon at the WSEC Monofill was updated.
- Post-closure costs for groundwater sampling and reporting were updated.
- Lifetimes for Neal North, LGS, and WSEC monofills have been updated based on the 2023 CCR placement volumes and recent filling rates.
- For the Neal South Monofill, closed in 2019, the number of years remaining of post-closure has been reduced by 1.
- For the Neal North Closed Monofill, closed in 2010, but permitted independently in 2021, the number of years remaining of post closure has been reduced by 1.
- For the LGS West (Closed) Monofill permitted separately in 2021, the number of years remaining of post-closure has been reduced by 1.
- A second estimate of costs assuming a 30-year post-closure period instead of 10 years has been provided again. The State of Iowa currently requires a 10-year post-closure monitoring period; however, it is anticipated the Iowa Department of Natural Resources (IDNR) will adopt rules consistent with United States Environmental Protection Agency's (USEPA's) final rules for Disposal of CCRs from Electric Utilities (40 CFR, Parts 257 and 261). The Neal North Closed Monofill post-closure period remains at 10 years in this estimate because it is not currently subject to the federal CCR rule.

1.4 2023 End-of-Year Estimated Remaining Permitted Capacity

The tonnage of CCR disposed in the Monofills is reported to the IDNR on a quarterly basis in the Fee-Exempt Report (DNR Form 542-8015). Due to the nature of these reports and recycling and reuse operations, the amounts reported may not fully reflect the amounts deposited or removed from the Monofills. The net tonnage of material deposited in each Monofill, less materials removed for beneficial use in 2023, is presented below.

Lifetimes for WSEC, LGS, Neal North, and WSEC have been updated based on the 2023 net CCR placement volumes:

- WSEC Monofill, 230,214 tons placed
- LGS Monofill, 61,808 tons placed
- Neal North Monofill, 28,092 tons placed

The values from the fee-exempt quarterly reports were used, as shown in Table 2, to calculate the Estimated Remaining Permitted Capacity (ERPC) for each Monofill. The general calculation uses the ERPC and subtracts the amount disposed in 2023 to generate the end of 2023 ERPC.

2. Site Conditions

The largest factor in the cost estimates is predicting the point at which the extent and manner of the Monofill operation would make closure the most expensive. Since completion of the cover is typically the most expensive component of construction, GHD has estimated when the greatest amount of cover soil would be required. The three operating monofills included in this estimate are to be closed with a geomembrane and earthen cover system; therefore, it is assumed MidAmerican will continue to complete partial capping activities as final grades are achieved. This has historically been completed at all three locations but has not yet been initiated on the currently active fill areas at Neal North or LGS.

At Neal North, significant grading occurred in 2019 and a temporary cover or rain cover was placed over a portion of the fill area to limit infiltration. In a sudden closure scenario, however, cover over the entire Monofill would still need to be constructed and additional grading work would be required.

2.1 WSEC Monofill

The WSEC Monofill is currently permitted for approximately 87 acres of Monofill footprint (Cells 1, 2, 3N, 3S, 4, 5, 6, 7, 8 and 9). The WSEC Monofill is a composite-lined facility. The final grades of the WSEC Monofill side slopes are up to 25 percent. The currently permitted WSEC Monofill is estimated to reach capacity in 2048. Based on the current estimated fill capacity and projected completion of the soil cover in stages, it is estimated the most expensive point at which to complete closure of the Monofill would be 2033, when final slopes are being met and an estimated 65 acres of surface area will remain to be capped.

2.2 LGS East (Active) Monofill

The LGS East Monofill is constructed with composite-lined cells. Cell 1 was completed in 2018 and Cells 2 and 3 were completed in 2019. The LGS East Monofill footprint is 11 acres.

The permitted capacity of the LGS East Monofill areas would last until 2025; however, an expansion will likely be completed prior to reaching permitted capacity. The most expensive point in closure is estimated as 2025 when there is significant open fill area due to rapidly reaching final grades. It is likely an expansion cell will be in use prior to this date.

2.3 LGS West (Closed) Monofill

The LGS West Monofill is in a bermed area with a footprint of approximately 34 acres and was closed in 2020. The LGS West Monofill was permitted independently of the LGS East Monofill in 2021. The LGS East Monofill is subject to the Federal CCR Rule. The first year of post-closure care is 2022 due to the permitting timeframe for separation from the LGS East Monofill.

2.4 Neal South Monofill

The Neal South Monofill covers approximately 32 acres. A composite cover was installed in 2018 including a 40-mil plastic liner with substantial construction completed in January 2019. The Neal South Monofill is closed, and closure costs are no longer applicable. Corrective measures for groundwater under the federal CCR rule were implemented in 2020 and the post-closure cost estimate reflects this additional cost.

2.5 Neal North Active Monofill

The Neal North Active Monofill consists of composite-lined Cells 1 and 2 (13.6 acres). A total of three composite-lined cells are currently approved for construction at Neal North with a capacity projected to allow disposal until 2066. In 2018, with the closure of the Neal South Monofill, CCR from Unit 4 was directed to the Neal North Monofill. In 2019, part of the Neal North Monofill was graded for a temporary rain cover to limit infiltration; however, this area is not graded to final conditions. It is estimated the most expensive point of closure is 2024 because no capping has been completed and import soil (likely from adjacent areas) or significant grading of the material under the rain cover will be required to assure the final cap can meet minimum grades.

2.6 Neal North Closed Monofill

The Neal North Closed Monofill consists of east and west fill areas (51 acres) where closure with an earthen cover system was completed in 2010. The Neal North Closed Monofill is regulated by the IDNR and does not currently fall under the federal CCR rule. The first year of post-closure is considered 2021 because the closed monofill areas were previously included in the same Operating Permit as the Neal North Active Monofill.

3. Closure Costs

The required components of the closure cost estimates listed in subparagraph 567—103.3(3)c(6), IAC are presented below. Supporting information is provided in Attachment A. Closure costs no longer apply to the Neal South Monofill and the Neal North Closed Monofill as closure construction is complete for these facilities.

3.1 Closure and Post-Closure Plan Document Revisions

These costs were estimated to be the same for WSEC, LGS, and Neal North Active Monofills. The scope of this component of the cost estimate includes a terrestrial survey, cap construction drawings, and closure and post-closure plan revisions. Since the point at which closure will be the most expensive is not consistent with the end of the life of the Monofill, new final cap drawings will need to be created and site conditions such as drainage and erosion control will need to be evaluated for all closure scenarios included in these estimates.

3.2 Site Preparation, Earthwork, and Final Grading

Site grading and preparation can include consolidating CCR, modifying existing temporary capping, or associated site and site access grading. For this component of the cost estimate, GHD has assumed no off-site material will be brought on site (grading fill for Neal North Active Monofill will be borrowed locally) and the cost components consist of excavating and recompacting material.

3.3 Drainage Control Culverts, Piping, and Structures

The actual drainage control culverts, piping, and structures would be evaluated at the time a final cap design is created. Currently, there are no calls for drainage piping or structures in the closure plans that would not have been installed during cell construction and operation.

3.4 Erosion Control Structures, Sediment Ponds, and Terraces

Erosion control structures, sediment ponds, and terraces will be determined during a final capping design. Most sites either have structures in place or do not include them in the current final plans. Stormwater terracing and channels are used in the current design for the Monofill caps. Costs for construction of the terraces and cap channels are included in the cap construction cost.

3.5 Final Cap Construction

The proposed capping system at all three Monofills incorporates a geomembrane to limit permeability. The alternative cap at WSEC and the East LGS Monofill includes 6 inches of recompacted clay overlain by 60-mil high-density polyethylene (HDPE) geomembrane and drainage composite, overlain by a 12-inch topsoil layer. The proposed closure cap at the Neal North Active Monofill did not incorporate a membrane prior to a 2021 Operating Permit renewal but now includes a 40-mil linear low density (LLDPE) geomembrane, drainage layer, 18-inch layer of protective soil and a 6-inch topsoil layer. For Neal North, the earthen materials are available on-site or from adjacent parcels.

3.6 Cap Vegetation Soil Placement

It is assumed the vegetative soil layer, or topsoil layer, will be imported for WSEC and LGS. For Neal North, local borrow is likely feasible based on a 2018 investigation of MidAmerican-owned parcels.

3.7 Cap Seeding, Mulching, and Fertilization

The same per-acre cost is assumed for the Monofill sites to address seeding, mulching, fertilizing, and establishment of vegetation on the final cap.

3.8 Monitoring Well and Piezometer Modifications

The monitoring well network at the Monofill sites should not need modifications to accommodate capping activities because adequate monitoring networks are already installed or will be installed as part of any future expansion construction.

3.9 Leachate System Cleanout and Extraction Well Modifications

The WSEC, Neal North Active, and LGS East Monofills have leachate collection systems; however, the leachate extraction and clean-out piping are accessible outside the cells and no modifications to the piping are anticipated as part of closure activities.

3.10 Monitoring Well Installations and Abandonments

It is not anticipated that additional monitoring wells will be required as part of closure activities because an approved monitoring network is in place. Although some wells may be plugged and abandoned at the time of closure, it is more likely all surrounding monitoring wells will remain until the end of the post-closure period. Thus, no costs for new monitoring well installation or abandonment are included in the closure cost estimate.

3.11 Facility Modifications to Affect Closed Status

Facility modifications to affect closed status is assumed to include updating of signage to indicate the Monofill is closed and securing gates as necessary.

3.12 Engineering and Technical Services

Engineering and technical services during closure activities include construction oversight, documentation, and field testing. Since the scope of these activities is tied to the amount of earthwork, costs are calculated as a percentage of the estimated cost for completion of closure construction activities.

3.13 Legal, Financial, and Administrative Services

The scope of third-party legal, financial, and administrative services required to complete closure activities will vary by the entity but includes adding a deed notation that the property was used as a CCR Monofill. To account for these costs, a uniform value has been applied to each Monofill project.

3.14 Closure Compliance Certifications and Documentation

The scope of closure compliance certifications and documentation includes providing the IDNR with assurance that the closure and construction activities have been completed in compliance with the permit. Documentation will likely include test results, construction photographs, and a signed engineer's statement attesting to completion of the closure activities. This category of the cost estimate is also expected to include updates to the IDNR during construction activities.

3.15 Corrective Measures for Groundwater

Under the federal CCR Rule, certain groundwater conditions may require implementation of corrective measures. None of the operating Monofills (Neal North Active, WSEC, or LGS East) currently require corrective measures. The closed LGS West Monofill also does not require corrective measures, however, corrective measures have been implemented for the closed Neal South Monofill.

4. Post-Closure Costs

The required components of the post-closure cost estimates listed in subparagraph 567—103.3(4)c(6), IAC are presented below. The post-closure period is assumed to be 10 years based on the current operating permits. Monitoring costs have also been updated based on the federal CCR rule analyte lists. Attachment A includes costs based on 10 years of post-closure monitoring; however, to reflect anticipated changes to state regulations for consistency with new federal regulations, separate calculations were completed for a 30-year post-closure period (except for the Neal North Closed Monofill). These values are shown in Table 3. 2024 represents year 6 of post-closure of the Neal South Monofill (including 2024, there are 5 years left of the post-closure period), year 4 of post-closure for the Neal North Closed Monofill (7 years remaining of post-closure remaining), and year 3 of post-closure for the LGS West Monofill (8 years of post-closure period remaining).

4.1 General Site Facilities, Access Roads, and Fencing Maintenance

During the post-closure period, site access roads must be maintained to permit cap maintenance. Site control through fencing must also be maintained. The amount of maintenance required will vary from site to site and be dependent on weather and adjacent site activities. A maintenance allowance has been allotted for each year of the post-closure period; however, the actual annual maintenance activities and costs are expected to vary.

4.2 Cap and Vegetative Cover Maintenance

Erosion of the cap must be monitored during the post-closure period and damage repaired. An allowance has been made for annual repair; however, the scope of maintenance activities will be highly dependent on-site conditions and activities.

4.3 Drainage and Erosion Control System Maintenance

Maintenance of a drainage and erosion control system may include removing soil or vegetation from drainage ways, replacing riprap, or other erosion control methods. As with other maintenance activities, the actual scope of required work will be highly variable and a maintenance allowance has been made in the cost estimates.

4.4 Groundwater-to-Waste Separation Systems Maintenance

4.4.1 WSEC Monofill

During construction of Cells 1 and 2 at the WSEC Monofill, high groundwater conditions were observed that are believed to be anomalous. The IDNR stated if the high groundwater conditions were not anomalous, then MidAmerican would have to complete active measures to maintain the minimum 5-foot separation distance between the CCR in the Monofill and high groundwater elevation. The base was raised in the design for subsequent cells. At this time, it is not anticipated any active system will be required to maintain the groundwater-to-waste separation distance at the WSEC Monofill.

4.4.2 Neal North Active, Neal North Closed, Neal South, LGS East, and LGS West Monofills

Based on site conditions at these facilities, no costs are allocated for maintenance or operation of a groundwater-to-waste separation system.

4.5 Groundwater and Surface Water Monitoring Systems Maintenance

Maintenance of monitoring wells may include installation of replacement wells, replacement of protective casings, grading around wells, or surveying. To account for the possibility of these maintenance activities, an annual allowance has been made in the cost estimate. There is no surface water sampling requirement in the current IDNR-approved monitoring networks for any of the listed facilities.

At the conclusion of the post-closure period, monitoring wells will be abandoned. Costs for well abandonment at the end of the post-closure period are included in another component of the cost estimate.

For the Neal North Closed Monofill, it is assumed that monitoring wells will remain in place after the post-closure period because they may continue to provide valuable data to other adjacent or overlapping monitoring works. The annual allowance for monitoring well repairs at the Neal North Closed Monofill is also significantly less because much of the network is associated with other monitoring networks where repair costs are accounted for. For the 2024 estimates, 3 additional monitoring wells were added to the total for the WSEC Monofill.

4.6 Groundwater and Surface Water Quality Monitoring and Reports

Semi-annual groundwater sampling and annual reporting are required during the post-closure period. The sampling costs have been updated based on recent contractor bids. Monitoring programs for the Monofills have been amended in the operating permit to reflect the federal monitoring requirements.

4.7 Groundwater Monitoring Systems Performance Evaluations and Reports

Evaluations of the groundwater monitoring systems are included in the annual water quality monitoring report and no additional costs are allocated.

4.8 Leachate Control Systems Maintenance

The WSEC, Neal North Active, and LGS East Monofills have leachate collection systems that will remain in operation during closure and post-closure. Video logging of the collection and extraction pipes at WSEC has shown no cleaning efforts are required after over a decade of operation. Due to the nature of the CCR, it is anticipated some mineral scaling may occur, but not to the point of requiring significant cleaning due to low quantities of leachate and large, 8-inch-diameter laterals. As operational data become available in future years, these assumptions may be revised.

The small-scale leachate collection system at Neal South is anticipated to remain in place during a portion of the closure period but have minimal operation requirements.

The LGS West Monofill and the Neal North Closed Monofill do not include leachate control systems.

4.9 Leachate Management, Transportation, and Disposal

4.9.1 WSEC Monofill

Upon closure, there will be approximately 87 acres requiring leachate management. An annual allowance has been made for costs associated with extraction, transportation, and treatment of 2,400,000 gallons of leachate for the 10-year post-closure period. To reflect the declining rate of leachate generation over time, the 30-year post-closure estimate assumes an average of 1,500,000 gallons of leachate per year. The City of Council Bluffs Wastewater Treatment Plant, located north of the Monofill, will accept the leachate.

4.9.2 Neal North Monofill

Upon closure, Cells 1, 2, and 3 will require leachate management. In 2018, a leachate pond was constructed at Neal North. Leachate management is under review. The estimate reflects hauling 500,000 gallons of leachate to the City of Sioux City Wastewater Treatment Plant annually.

4.9.3 Neal South Monofill

A small-scale leachate collection system is currently in use at the Neal South Monofill. For the purposes of estimating ongoing post-closure costs, it is assumed the system will be abandoned prior to final closure. Costs have been included for collecting and hauling leachate to the Neal North leachate pond and for abandonment in place of the collection system.

4.9.4 LGS East Monofill

The LGS East Monofill includes a leachate collection system and thus, costs are included for managing leachate at LGS.

4.10 Leachate Control Systems Performance Evaluations and Reports

An annual report of leachate production and management system performance is required during the post-closure period. The data for assessment of the control system would be acquired during the leachate management, transportation, and disposal operations. Additional costs are allocated to prepare the annual leachate system performance evaluation.

4.11 Facility Inspections and Reports

An annual engineering inspection of the completed cap is required. The engineering inspection will be documented in a report to the IDNR. The inspection typically consists of visual observation of the cover and noted apparent deficiencies in the cap thickness, erosion patterns, or areas where vegetation is not established.

4.12 Engineering and Technical Services

An annual allowance for engineering and technical services has been made in the cost estimate. The scope of engineering services during the post-closure period will likely be limited to support for any permit modifications or changes to erosion control features. Additional services such as groundwater sampling or the annual engineering inspection are included in other components of the cost estimate.

4.13 Legal, Financial, and Administrative Services

The scope of third-party legal, financial, and administrative services required to complete closure activities will vary by the entity. To account for these costs, a uniform value has been applied to each of the four Monofill projects.

4.14 Financial Assurance, Accounting, Audits, and Reports

The costs of third-party financial assurance, accounting, audits, and reports are difficult to assess because the requirements may vary from site to site. To account for these costs, a uniform value has been applied for each year of the post-closure period.

4.15 Corrective Measures for Groundwater

Under the federal CCR Rule, certain groundwater conditions may require implementation of corrective measures. The Neal South Monofill, which is in the post-closure period, was identified for implementation of corrective measures. Corrective measures were initiated at the Neal South Monofill in 2020 and the additional noted costs reflect a remaining 3-year period of monitoring and reporting.

Regards,

Michael Alowitz

Michael J. Alowitz, P.E.
Senior Engineer

515 414-3934
michael.alowitz@ghd.com

Kevin G. Armstrong

Kevin G. Armstrong, C.P.G., P.M.P.
Project Manager

515 414-3935
kevin.armstrong@ghd.com

MA/lg/LTR-07

Encl.

Copy to: Josh Love, MidAmerican

Table 1

Summary of Closure/Post-Closure Cost Estimates
MidAmerican Energy Company
Coal Combustion Residue Monofills
March 2024

	NN Active	NN Closed	Neal South	WSEC	LGS-West	LGS-East	TOTAL
Calculation Closure Year	2024	Closed	Closed	2033	Closed	2025	
Initiated Post-Closure	Active	2021	2019	Active	2022	Active	
Total Dollars							
Current Closure Cost	$3,364,000	-	-	$19,031,000	-	$2,760,000	
Current Post-Closure Cost	$1,476,000	$494,000	$776,000	$5,437,000	$767,000	$1,266,000	
Total Dollar Value	$4,840,000	$494,000	$776,000	$24,468,000	$767,000	$4,026,000	
Total (All Facilities)							**$35,371,000**

Notes:
Supporting calculations provided on additional sheets.
NN - Neal North
WSEC - Walter Scott, Jr. Energy Center.
LGS - Louisa Generating Station.

This table reflects a post-closure period of 10 years, consistent with current permit requirements.

Table 2

2023 Estimated Remaining Permitted Capacities (ERPCs)
MidAmerican Energy Company
Coal Combustion Residue Monofills
March 2024

	Permitted Cells	ERPC Through 2022 Tons A	Capacity Adjustment Tons B	Tons Disposed 2023 Tons C	ERPC Through 2023 Tons (A+B) - C
LGS	East 1, 2, and 3	170,370	-	61,808	108,562
Neal North	1, 2, and 3	1,288,857	-	38,092	1,250,765
Neal South	Closed	-	-	-	-
WSEC	1 through 9	6,004,438	0	230,214	5,774,224

Notes:
WSEC - Walter Scott, Jr. Energy Center.
LGS - Louisa Generating Station.
ERPC - Estimated remaining permitted capacity.
Neal South Monofill was closed in 2018.
WSEC capacity adjustment reflects completion of Cell 9 and updated survey work.

Table 3

Summary of Closure/Post-Closure Cost Estimates with 30-Year Post-Closure Period
MidAmerican Energy Company
Coal Combustion Residue Monofills
March 2024

	NN Active	NN Closed	Neal South	WSEC	LGS-West	LGS-East	TOTAL
Calculation Closure Year	2024	Closed	Closed	2033	Closed	2025	
Initiated Post-Closure	Active	2021	2019	Active	2022	Active	
Total Dollars							
Current Closure Cost	$3,364,000	-	-	$19,031,000	-	$2,872,000	
Current Post-Closure Cost	$4,313,000	$494,000	$3,270,000	$15,950,000	$2,763,000	$3,772,000	
Total Dollar Value	$7,677,000	$494,000	$3,270,000	$34,981,000	$2,763,000	$6,644,000	
Total (All Facilities)							**$55,829,000**

Notes:
NN - Neal North
WSEC - Walter Scott, Jr. Energy Center.
LGS - Louisa Generating Station.
Supporting calculations provided on additional sheets.

This table reflects a 30-year post-closure period, consistent with the federal CCR Rule where applicable except for NN Closed.

Attachments

Attachment A

Cost Estimate Supporting Calculations

Neal North Active CCR Monofill
Closure and Post-Closure Cost Estimate
March 2024

		Unit	Unit Cost	Quantity	Total
CLOSURE					
1	Closure and Post-Closure Plan (C/PC) document revisions.				
	C/PC Plan, Hydrologic Monitoring System Plan (HMSP)	Lump	$55,368	1	$55,368
	Survey	Lump	$16,610	1	$16,610
2	Site preparation, earthwork, and final grading.				
	Grading (For Filling Cell 2 Area)	CY	$6.10	10,000	$61,031
	Coal Combustion Residue (CCR) Grading	CY	$4.97	5,000	$24,829
3	Drainage control culverts, piping, and structures.	Lump	$0	0	$0
4	Erosion control structures, sediment ponds, and terraces.	Lump	$0	0	$0
5	Final cap Earthen construction.	CY	$13.07	29,000	$379,022
	60-mil HDPE and drainage Layer	SF	$3.44	575,000	$1,975,418
6	Cap vegetation soil placement.	CY	$11.88	9,667	$114,855
	Mobilization/Appurtenant Work (percent of earthwork)	Percent	5%	1	$127,758
7	Cap seeding, mulching, and fertilization.	Acre	$5,689	10	$56,894
8	Monitoring well and piezometer modifications.	Lump	$0	0	$0
9	Leachate system cleanout and extraction well modifications.	Lump	$0	0	$0
10	Monitoring well installations and abandonments.	Lump	$0	0	$0
11	Facility modifications to effect closed status.	Lump	$3,216	1	$3,216
12	Engineering and technical services (percent of earthwork).	Percent	15%	1	$410,971
13	Legal, financial, and administrative services.	Lump	$69,210	1	$69,210
14	Closure compliance certifications and documentation.	Lump	$69,210	1	$69,210
15	Corrective measures for groundwater.	Lump	$0	0	$0
			Closure Subtotal		**$3,364,394**
10 YEAR POST CLOSURE (CURRENT PERMIT)					
1	General site facilities, access roads, and fencing maintenance.	Annual	$6,921	10	$69,210
2	Cap and vegetative cover maintenance.	Annual	$6,921	10	$69,210
3	Drainage and erosion control system maintenance.	Annual	$2,768	10	$27,684
4	Groundwater to waste separation systems maintenance.	Annual	$0	0	$0
5	Groundwater and surface water monitoring systems maintenance.				
	Annual Allowance for Repairs	Annual	$1,384	10	$13,842
	Well Abandonment	Well (one time)	$831	33	$27,407
6	Groundwater/surface water quality gauging and sampling.	Semiannual	$6,500	20	$130,000
7	Groundwater/surface water evaluations and reports.	Annual	$23,000	10	$230,000
8	Leachate control systems maintenance.	Annual	$6,785	10	$67,847
9	Leachate management, transportation, and disposal.	Annual	$31,463	10	$314,625
10	Leachate control systems performance evaluations and reports.	Annual	$5,536	10	$55,363
11	Facility inspections and reports.	Annual	$5,537	10	$55,368
12	Engineering and technical services.	Annual	$13,842	10	$138,420
13	Legal, financial, and administrative services.	Annual	$13,842	10	$138,420
14	Financial assurance, accounting, audits, and reports.	Annual	$13,842	10	$138,420
15	Corrective measures for groundwater.	Lump	$0	0	$0
			Post-Closure Subtotal		**$1,475,818**

Notes:
Start Date For Financial Calculations is March 1, 2024.

Neal North Active CCR Monofill
30-Year Closure and Post-Closure Cost Estimate
March 2024

		Unit	Unit Cost	Quantity	Total
CLOSURE					
1	Closure and Post-Closure Plan (C/PC) document revisions.				
	C/PC Plan, Hydrologic Monitoring System Plan (HMSP)	Lump	$55,368	1	$55,368
	Survey	Lump	$16,610	1	$16,610
2	Site preparation, earthwork, and final grading.				
	Grading (For Filling Cell 2 Area)	CY	$6.10	10,000	$61,031
	Coal Combustion Residue (CCR) Grading	CY	$4.97	5,000	$24,829
3	Drainage control culverts, piping, and structures.	Lump	$0	0	$0
4	Erosion control structures, sediment ponds, and terraces.	Lump	$0	0	$0
5	Final cap Earthen construction.	CY	$13.07	29,000	$379,022
	60-mil HDPE and drainage Layer	SF	$3.44	575,000	$1,975,418
6	Cap vegetation soil placement.	CY	$11.88	9,667	$114,855
	Mobilization/Appurtenant Work (percent of earthwork)	Percent	5%	1	$127,758
7	Cap seeding, mulching, and fertilization.	Acre	$5,689	10	$56,894
8	Monitoring well and piezometer modifications.	Lump	$0	0	$0
9	Leachate system cleanout and extraction well modifications.	Lump	$0	0	$0
10	Monitoring well installations and abandonments.	Lump	$0	0	$0
11	Facility modifications to effect closed status.	Lump	$3,216	1	$3,216
12	Engineering and technical services (percent of earthwork).	Percent	15%	1	$410,971
13	Legal, financial, and administrative services.	Lump	$69,210	1	$69,210
14	Closure compliance certifications and documentation.	Lump	$69,210	1	$69,210
15	Corrective measures for groundwater.	Lump	$0	0	$0
			Closure Subtotal		**$3,364,394**
30 YEAR POST CLOSURE (FEDERAL CCR RULE)					
1	General site facilities, access roads, and fencing maintenance.	Annual	$6,746	30	$202,369
2	Cap and vegetative cover maintenance.	Annual	$6,746	30	$202,369
3	Drainage and erosion control system maintenance.	Annual	$2,698	30	$80,948
4	Groundwater to waste separation systems maintenance.	Annual	$0	0	$0
5	Groundwater and surface water monitoring systems maintenance.				
	Annual Allowance for Repairs	Annual	$1,349	30	$40,474
	Well Abandonment	Well (one time)	$809	33	$26,713
6	Groundwater/surface water quality gauging and sampling.	Semiannual	$6,500	60	$390,000
7	Groundwater/surface water evaluations and reports.	Annual	$23,000	30	$690,000
8	Leachate control systems maintenance.	Annual	$6,613	30	$198,383
9	Leachate management, transportation, and disposal.	Annual	$31,463	30	$943,875
10	Leachate control systems performance evaluations and reports.	Annual	$5,396	30	$161,881
11	Facility inspections and reports.	Annual	$5,397	30	$161,895
12	Engineering and technical services.	Annual	$13,491	30	$404,738
13	Legal, financial, and administrative services.	Annual	$13,491	30	$404,738
14	Financial assurance, accounting, audits, and reports.	Annual	$13,491	30	$404,738
15	Corrective measures for groundwater.	Lump	$0	0	$0
			Post-Closure Subtotal		**$4,313,120**

Notes:
Start Date For Financial Calculations is March 1, 2024.

Neal North Closed CCR Monofill
Closure and Post-Closure Cost Estimate
March 2024

		Unit	Unit Cost	Quantity	Total
10 YEAR POST CLOSURE (CURRENT PERMIT)					
1	General site facilities, access roads, and fencing maintenance.	Annual	$6,921	7	$48,447
2	Cap and vegetative cover maintenance.	Annual	$6,921	7	$48,447
3	Drainage and erosion control system maintenance.	Annual	$2,768	7	$19,379
4	Groundwater to waste separation systems maintenance.	Annual	$0	0	$0
5	Groundwater and surface water monitoring systems maintenance.				
	Annual Allowance for Repairs	Annual	$346	7	$2,424
	Well Abandonment	Well (one time)	$0	0	$0
6	Groundwater/surface water quality gauging and sampling.	Semiannual	$7,000	14	$98,000
7	Groundwater/surface water evaluations and reports.	Annual	$17,000	7	$119,000
8	Leachate control systems maintenance.	Annual	$0	0	$0
9	Leachate management, transportation, and disposal.	Annual	$0	0	$0
10	Leachate control systems performance evaluations and reports.	Annual	$0	0	$0
11	Facility inspections and reports.	Annual	$5,468	7	$38,275
12	Engineering and technical services.	Annual	$5,772	7	$40,405
13	Legal, financial, and administrative services.	Annual	$5,626	7	$39,381
14	Financial assurance, accounting, audits, and reports.	Annual	$5,772	7	$40,405
15	Corrective measures for groundwater.	Lump	$0	0	$0
			Post-Closure Subtotal		**$494,165**

Notes:
Start Date For Financial Calculations is March 1, 2024.
2022 was the second year of post-closure period.

Neal South CCR Monofill
Post-Closure Cost Estimate
March 2024

		Unit	Unit Cost	Quantity	Total
10 YEAR POST CLOSURE CURRENT PERMIT)					
1	General site facilities, access roads, and fencing maintenance.	Annual	$6,921	5	$34,605
2	Cap and vegetative cover maintenance.	Annual	$6,921	5	$34,605
3	Drainage and erosion control system maintenance.	Annual	$2,768	5	$13,842
4	Groundwater to waste separation systems maintenance.	Annual	$0	0	$0
5	Groundwater and surface water monitoring systems maintenance.				
	Annual Allowance for Repairs	Annual	$1,384	5	$6,921
	Well Abandonment	Well (one time)	$817	52	$42,507
6	Groundwater/surface water quality gauging and sampling.	Semiannual	$20,000	10	$200,000
7	Groundwater/surface water evaluations and reports.	Annual	$18,000	5	$90,000
8	Leachate control systems maintenance.	Lump	$2,376	1	$2,376
9	Leachate management, transportation, and disposal.	Annual	$4,753	3	$14,258
10	Leachate control systems performance evaluations and reports.	Annual	$1,237	3	$3,712
11	Facility inspections and reports.	Annual	$5,537	5	$27,684
12	Engineering and technical services.	Annual	$13,842	5	$69,210
13	Legal, financial, and administrative services.	Annual	$13,842	5	$69,210
14	Financial assurance, accounting, audits, and reports.	Annual	$13,842	5	$69,210
15	Corrective measures for groundwater.	Annual	$32,719	3	$98,157
			Post-Closure Subtotal		**$776,299**

Notes:
Start Date For Financial Calculations is March 1, 2024.
2022 was the fourth year of post-closure period.

Neal South CCR Monofill
30-Year Post-Closure Cost Estimate
March 2024

		Unit	Unit Cost	Quantity	Total
30 YEAR POST CLOSURE (FEDERAL CCR RULE)					
1	General site facilities, access roads, and fencing maintenance.	Annual	$6,921	25	$173,025
2	Cap and vegetative cover maintenance.	Annual	$6,921	25	$173,025
3	Drainage and erosion control system maintenance.	Annual	$2,768	25	$69,210
4	Groundwater to waste separation systems maintenance.	Annual	$0	0	$0
5	Groundwater and surface water monitoring systems maintenance.				
	Annual Allowance for Repairs	Annual	$1,384	25	$34,605
	Well Abandonment	Well (one time)	$817	52	$42,507
6	Groundwater/surface water quality gauging and sampling.	Semiannual	$20,000	50	$1,000,000
7	Groundwater/surface water evaluations and reports.	Annual	$18,000	25	$450,000
8	Leachate control systems maintenance.	Lump	$2,376	1	$2,376
9	Leachate management, transportation, and disposal.	Annual	$4,753	3	$14,258
10	Leachate control systems performance evaluations and reports.	Annual	$1,237	3	$3,712
11	Facility inspections and reports.	Annual	$5,537	25	$138,420
12	Engineering and technical services.	Annual	$13,842	25	$346,051
13	Legal, financial, and administrative services.	Annual	$13,842	25	$346,051
14	Financial assurance, accounting, audits, and reports.	Annual	$13,842	25	$346,051
15	Corrective measures for groundwater.	Annual	$32,719	4	$130,877
			Post-Closure Subtotal		**$3,270,170**

Notes:
Start Date For Financial Calculations is March 1, 2024.
2022 was the fourth year of post-closure period.

Louisa Generating Station West (Closed) CCR Monofill
Post-Closure Cost Estimate
March 2024

		Unit	Unit Cost	Quantity	Total
10 YEAR POST CLOSURE (CURRENT PERMIT)					
1	General site facilities, access roads, and fencing maintenance.	Annual	$6,921	8	$55,368
2	Cap and vegetative cover maintenance.	Annual	$6,921	8	$55,368
3	Drainage and erosion control system maintenance.	Annual	$2,768	8	$22,147
4	Groundwater to waste separation systems maintenance.	Annual	$0	0	$0
5	Groundwater and surface water monitoring systems maintenance.				
	Annual Allowance for Repairs	Annual	$1,384	8	$11,074
	Well Abandonment	Well (one time)	$817	8	$6,540
6	Groundwater/surface water quality gauging and sampling.	Semiannual	$6,500	16	$104,000
7	Groundwater/surface water evaluations and reports.	Annual	$17,000	8	$136,000
8	Leachate control systems maintenance.	Annual	$0	8	$0
9	Leachate management, transportation, and disposal.	Annual	$0	8	$0
10	Leachate control systems performance evaluations and reports.	Annual	$0	8	$0
11	Facility inspections and reports.	Annual	$5,537	8	$44,295
12	Engineering and technical services.	Annual	$13,842	8	$110,736
13	Legal, financial, and administrative services.	Annual	$13,842	8	$110,736
14	Financial assurance, accounting, audits, and reports.	Annual	$13,842	8	$110,736
15	Corrective measures for groundwater.	Lump	$0	0	$0
			Post-Closure Subtotal		**$767,000**

Notes:
Start Date For Financial Calculations is March 1, 2024.
2022 was the first year of post-closure period.

Louisa Generating Station West (Closed) CCR Monofill
30-Year Post-Closure Cost Estimate
March 2024

		Unit	Unit Cost	Quantity	Total
30 YEAR POST CLOSURE (FEDERAL CCR RULE)					
1	General site facilities, access roads, and fencing maintenance.	Annual	$6,921	29	$200,710
2	Cap and vegetative cover maintenance.	Annual	$6,921	29	$200,710
3	Drainage and erosion control system maintenance.	Annual	$2,768	29	$80,284
4	Groundwater to waste separation systems maintenance.	Annual	$0	0	$0
5	Groundwater and surface water monitoring systems maintenance.				
	Annual Allowance for Repairs	Annual	$1,384	29	$40,142
	Well Abandonment	Well (one time)	$817	8	$6,540
6	Groundwater/surface water quality gauging and sampling.	Semiannual	$6,500	58	$377,000
7	Groundwater/surface water evaluations and reports.	Annual	$17,000	29	$493,000
8	Leachate control systems maintenance.	Annual	$0	29	$0
9	Leachate management, transportation, and disposal.	Annual	$0	29	$0
10	Leachate control systems performance evaluations and reports.	Annual	$0	29	$0
11	Facility inspections and reports.	Annual	$5,537	29	$160,568
12	Engineering and technical services.	Annual	$13,842	29	$401,419
13	Legal, financial, and administrative services.	Annual	$13,842	29	$401,419
14	Financial assurance, accounting, audits, and reports.	Annual	$13,842	29	$401,419
15	Corrective measures for groundwater.	Lump	$0	0	$0
			Post-Closure Subtotal		**$2,763,209**

Notes:
Start Date For Financial Calculations is March 1, 2024.
2022 was the first year of post-closure period.

Louisa Generating Station East (Active) CCR Monofill
Closure and Post-Closure Cost Estimate
March 2024

		Unit	Unit Cost	Quantity	Total
CLOSURE					
1	Closure and Post-Closure Plan (C/PC) document revisions.				
	C/PC Plan, Hydrologic Monitoring System Plan (HMSP)	Lump	$55,368	1	$55,368
	Survey	Lump	$16,610	1	$16,610
2	Site preparation, earthwork, and final grading.				
	Grading	CY	$10.51	5,000	$52,536
	Coal Combustion Residue (CCR) Grading	CY	$4.97	10,000	$49,658
3	Drainage control culverts, piping, and structures.	Lump	$49,495	1	$49,495
4	Erosion control structures, sediment ponds, and terraces.	Lump	$0	0	$0
5	Final cap Earthen construction.	CY	$13.07	8,067	$105,429
	60-mil HDPE and drainage Layer	SF	$4.04	435,600	$1,760,060
6	Cap vegetation soil placement.	CY	$16.37	1,613	$26,404
	Mobilization/Appurtenant Work (percent of earthwork)	Percent	5%	1	$102,179
7	Cap seeding, mulching, and fertilization.	Acre	$5,689	12	$68,273
8	Monitoring well and piezometer modifications.	Lump	$0	0	$0
9	Leachate system cleanout and extraction well modifications.	Lump	$0	0	$0
10	Monitoring well installations and abandonments.	Lump	$0	0	$0
11	Facility modifications to effect closed status.	Lump	$3,216	1	$3,216
12	Engineering and technical services (percent of earthwork).	Percent	15%	1	$332,105
13	Legal, financial, and administrative services.	Lump	$69,210	1	$69,210
14	Closure compliance certifications and documentation.	Lump	$69,210	1	$69,210
15	Corrective measures for groundwater.	Lump	$0	0	$0
			Closure Subtotal		**$2,759,753**
10 YEAR POST CLOSURE (CURRENT PERMIT)					
1	General site facilities, access roads, and fencing maintenance.	Annual	$6,921	10	$69,210
2	Cap and vegetative cover maintenance.	Annual	$6,921	10	$69,210
3	Drainage and erosion control system maintenance.	Annual	$2,768	10	$27,684
4	Groundwater to waste separation systems maintenance.	Annual	$0	0	$0
5	Groundwater and surface water monitoring systems maintenance.				
	Annual Allowance for Repairs	Annual	$1,384	10	$13,842
	Well Abandonment	Well (one time)	$817	15	$12,262
6	Groundwater/surface water quality gauging and sampling.	Semiannual	$7,500	20	$150,000
7	Groundwater/surface water evaluations and reports.	Annual	$17,000	10	$170,000
8	Leachate control systems maintenance.	Annual	$6,071	10	$60,715
9	Leachate management, transportation, and disposal.	Annual	$18,561	10	$185,605
10	Leachate control systems performance evaluations and reports.	Annual	$3,643	10	$36,429
11	Facility inspections and reports.	Annual	$5,537	10	$55,368
12	Engineering and technical services.	Annual	$13,842	10	$138,420
13	Legal, financial, and administrative services.	Annual	$13,842	10	$138,420
14	Financial assurance, accounting, audits, and reports.	Annual	$13,842	10	$138,420
15	Corrective measures for groundwater.	Lump	$0	0	$0
			Post-Closure Subtotal		**$1,265,587**

Notes:
Start Date For Financial Calculations is March 1, 2024.

Louisa Generating Station East (Active) CCR Monofill
30-Year Closure and Post-Closure Cost Estimate
March 2024

		Unit	Unit Cost	Quantity	Total
CLOSURE					
1	Closure and Post-Closure Plan (C/PC) document revisions.				
	C/PC Plan, Hydrologic Monitoring System Plan (HMSP)	Lump	$53,965	1	$53,965
	Survey	Lump	$16,190	1	$16,190
2	Site preparation, earthwork, and final grading.				
	Grading	CY	$10.24	5,000	$51,205
	Coal Combustion Residue (CCR) Grading	CY	$4.84	30,000	$145,199
3	Drainage control culverts, piping, and structures.	Lump	$49,495	1	$49,495
4	Erosion control structures, sediment ponds, and terraces.	Lump	$0	0	$0
5	Final cap Earthen construction.	CY	$13.07	8,067	$105,429
	60-mil LLDPE and drainage Layer	SF	$4.04	435,600	$1,760,060
6	Cap vegetation soil placement.	CY	$16.37	1,613	$26,404
	Mobilization/Appurtenant Work (percent of earthwork)	Percent	5%	1	$106,890
7	Cap seeding, mulching, and fertilization.	Acre	$5,689	12	$68,273
8	Monitoring well and piezometer modifications.	Lump	$0	0	$0
9	Leachate system cleanout and extraction well modifications.	Lump	$0	0	$0
10	Monitoring well installations and abandonments.	Lump	$0	0	$0
11	Facility modifications to effect closed status.	Lump	$3,216	1	$3,216
12	Engineering and technical services (percent of earthwork).	Percent	15%	1	$346,943
13	Legal, financial, and administrative services.	Lump	$69,210	1	$69,210
14	Closure compliance certifications and documentation.	Lump	$69,210	1	$69,210
15	Corrective measures for groundwater.	Lump	$0	0	$0
			Closure Subtotal		**$2,871,687**
30 YEAR POST CLOSURE (FEDERAL CCR RULE)					
1	General site facilities, access roads, and fencing maintenance.	Annual	$6,921	30	$207,631
2	Cap and vegetative cover maintenance.	Annual	$6,921	30	$207,631
3	Drainage and erosion control system maintenance.	Annual	$2,768	30	$83,052
4	Groundwater to waste separation systems maintenance.	Annual	$0	0	$0
5	Groundwater and surface water monitoring systems maintenance.				
	Annual Allowance for Repairs	Annual	$1,384	30	$41,526
	Well Abandonment	Well (one time)	$817	15	$12,262
6	Groundwater/surface water quality gauging and sampling.	Semiannual	$7,500	60	$450,000
7	Groundwater/surface water evaluations and reports.	Annual	$17,000	30	$510,000
8	Leachate control systems maintenance.	Annual	$6,071	30	$182,145
9	Leachate management, transportation, and disposal.	Annual	$18,561	30	$556,816
10	Leachate control systems performance evaluations and reports.	Annual	$3,643	30	$109,287
11	Facility inspections and reports.	Annual	$5,537	30	$166,104
12	Engineering and technical services.	Annual	$13,842	30	$415,261
13	Legal, financial, and administrative services.	Annual	$13,842	30	$415,261
14	Financial assurance, accounting, audits, and reports.	Annual	$13,842	30	$415,261
15	Corrective measures for groundwater.	Lump	$0	0	$0
			Post-Closure Subtotal		**$3,772,236**

Notes:
Start Date For Financial Calculations is March 1, 2024.

Walter Scott, Jr. Energy Center CCR Monofill
Closure and Post-Closure Cost Estimate
March 2024

		Unit	Unit Cost	Quantity	Total
CLOSURE					
1	Closure and Post-Closure Plan (C/PC) document revisions.				
	C/PC Plan, Hydrologic Monitoring System Plan (HMSP)	Lump	$55,368	1	$55,368
	Survey	Lump	$16,610	1	$16,610
2	Site preparation, earthwork, and final grading.				
	Grading	CY	$9.00	5,000	$44,987
	Coal Combustion Residue (CCR) Grading	CY	$14.38	15,000	$215,771
3	Drainage control culverts, piping, and structures.	Lump	$0	0	$0
4	Erosion control structures, sediment ponds, and terraces.	Lump	$0	0	$0
5	Final cap construction.	acres	$249,513	60	$14,970,786
6	Cap vegetation soil placement (included line 5).				
	Mobilization/Appurtenant Work (percent of earthwork)	Percent	5%	1	$761,577
7	Cap seeding, mulching, and fertilization.	Acre	$5,689	65	$369,812
8	Monitoring well and piezometer modifications.	Lump	$0	0	$0
9	Leachate system cleanout and extraction well modifications.	Lump	$0	0	$0
10	Monitoring well installations and abandonments.	Lump	$0	0	$0
11	Facility modifications to effect closed status.	Lump	$3,216	1	$3,216
12	Engineering and technical services (percent of earthwork).	Percent	15%	1	$2,454,440
13	Legal, financial, and administrative services.	Lump	$69,210	1	$69,210
14	Closure compliance certifications and documentation.	Lump	$69,210	1	$69,210
15	Corrective measures for groundwater.	Lump	$0	0	$0
			Closure Subtotal		**$19,030,988**
10 YEAR POST CLOSURE (CURRENT PERMIT)					
1	General site facilities, access roads, and fencing maintenance.	Annual	$6,921	10	$69,210
2	Cap and vegetative cover maintenance.	Annual	$6,921	10	$69,210
3	Drainage and erosion control system maintenance.	Annual	$2,768	10	$27,684
4	Groundwater to waste separation systems maintenance.	Annual	$0	0	$0
5	Groundwater and surface water monitoring systems maintenance.				
	Annual Allowance for Repairs	Annual	$1,384	10	$13,842
	Well Abandonment	Well (one time)	$831	32	$26,577
6	Groundwater/surface water quality gauging and sampling.	Semiannual	$7,000	20	$140,000
7	Groundwater/surface water evaluations and reports.	Annual	$17,000	10	$170,000
8	Leachate control systems maintenance.	Annual	$6,711	10	$170,000
9	Leachate management, transportation, and disposal.	Annual	$422,471	10	$4,224,709
10	Leachate control systems performance evaluations and reports.	Annual	$5,536	10	$55,363
11	Facility inspections and reports.	Annual	$5,537	10	$55,368
12	Engineering and technical services.	Annual	$13,842	10	$138,420
13	Legal, financial, and administrative services.	Annual	$13,842	10	$138,420
14	Financial assurance, accounting, audits, and reports.	Annual	$13,842	10	$138,420
15	Corrective measures for groundwater.	Lump	$0	0	$0
			Post-Closure Subtotal		**$5,437,224**

Notes:
Start Date For Financial Calculations is March 1, 2024.

Walter Scott, Jr. Energy Center CCR Monofill
Closure and 30-Year Post-Closure Cost Estimate
March 2024

		Unit	Unit Cost	Quantity	Total
CLOSURE					
1	Closure and Post-Closure Plan (C/PC) document revisions.				
	C/PC Plan, Hydrologic Monitoring System Plan (HMSP)	Lump	$55,368	1	$55,368
	Survey	Lump	$16,610	1	$16,610
2	Site preparation, earthwork, and final grading.				
	Grading	CY	$9.00	5,000	$44,987
	Coal Combustion Residue (CCR) Grading	CY	$14.38	15,000	$215,771
3	Drainage control culverts, piping, and structures.	Lump	$0	0	$0
4	Erosion control structures, sediment ponds, and terraces.	Lump	$0	0	$0
5	Final cap construction.	acres	$249,513	60	$14,970,786
6	Cap vegetation soil placement (included line 5).				
	Mobilization/Appurtenant Work (percent of earthwork)	Percent	5%	1	$761,577
7	Cap seeding, mulching, and fertilization.	Acre	$5,689	65	$369,812
8	Monitoring well and piezometer modifications.	Lump	$0	0	$0
9	Leachate system cleanout and extraction well modifications.	Lump	$0	0	$0
10	Monitoring well installations and abandonments.	Lump	$0	0	$0
11	Facility modifications to effect closed status.	Lump	$3,216	1	$3,216
12	Engineering and technical services (percent of earthwork).	Percent	15%	1	$2,454,440
13	Legal, financial, and administrative services.	Lump	$69,210	1	$69,210
14	Closure compliance certifications and documentation.	Lump	$69,210	1	$69,210
15	Corrective measures for groundwater.	Lump	$0	0	$0
			Closure Subtotal		**$19,030,988**
30 YEAR POST CLOSURE (FEDERAL CCR RULE)					
1	General site facilities, access roads, and fencing maintenance.	Annual	$6,921	30	$207,631
2	Cap and vegetative cover maintenance.	Annual	$6,921	30	$207,631
3	Drainage and erosion control system maintenance.	Annual	$2,768	30	$83,052
4	Groundwater to waste separation systems maintenance.	Annual	$0	0	$0
5	Groundwater and surface water monitoring systems maintenance.				
	Annual Allowance for Repairs	Annual	$1,384	30	$41,526
	Well Abandonment	Well (one time)	$831	32	$26,577
6	Groundwater/surface water quality gauging and sampling.	Semiannual	$7,000	60	$420,000
7	Groundwater/surface water evaluations and reports.	Annual	$17,000	30	$510,000
8	Leachate control systems maintenance.	Annual	$6,711	30	$201,327
9	Leachate management, transportation, and disposal.	Annual	$422,471	30	$12,674,126
10	Leachate control systems performance evaluations and reports.	Annual	$5,536	30	$166,090
11	Facility inspections and reports.	Annual	$5,537	30	$166,104
12	Engineering and technical services.	Annual	$13,842	30	$415,261
13	Legal, financial, and administrative services.	Annual	$13,842	30	$415,261
14	Financial assurance, accounting, audits, and reports.	Annual	$13,842	30	$415,261
15	Corrective measures for groundwater.	Lump	$0	0	$0
			Post-Closure Subtotal		**$15,949,846**

Notes:
Start Date For Financial Calculations is March 1, 2024.

Attachment B

Inflation Factor

The 'Inflation Factor'– 2023 over 2022 for Landfill Financial Assistance Cost Estimates

Ref. Iowa Admin. Code [567] sub-sections (3), (4) & (5) in each of sections 113.14, 115.31, 114.31 & 103.3

Every Annual Financial Assurance Report must UPDATE Closure, Postclosure &/or Corrective Action Cost Estimates, **IN CURRENT DOLLARS**, certified by an Iowa-licensed professional engineer.

IF no other re-assessment/computations are done**, Cost Estimates HAVE TO **AT LEAST** BE adjusted for annual inflation By **multiplying** last year's Cost Estimates **times** the **Inflation Factor**.

As of *January 25, 2024*, the Inflation Factor for this year's Financial Assurance Reports is **1.026**

as Derived from Gross Domestic Product statistics, using the formula:

Implicit Price Deflator of most recent quarter ÷ Implicit Price Deflator of previous year's same corresponding quarter	= **Inflation Factor**

Find the Implicit Price Deflators for GROSS DOMESTIC PRODUCT at this website of the U.S. Dept. of Commerce, Bureau of Economic Analysis (BEA):
https://apps.bea.gov/iTable/?reqid=19&step=3&isuri=1&1921=survey&1903=13

So it is then that:

$$\frac{\textbf{2023}\ 4^{th}\ \text{quarter implicit price deflator}}{\textbf{2022}\ 4^{th}\ \text{quarter implicit price deflator}} = \textbf{Inflation Factor}$$

123.226 **120.093**	= **1.026**

*as An **Example***, ---with No other re-assessment/re-computations** being made...

IF, Last *Year's combined Cost Estimates* = **$2,000,000**

Applying this year's Inflation Factor then *means*:

$2,000,000* X 1.026 = *$2,052,000

i.e. This Year's updated combined Cost Estimates adjusted for inflation.

Source of the Implicit Price Deflators for **GROSS DOMESTIC PRODUCT**:

U.S. Department of Commerce
Bureau of Economic Analysis (BEA)
4600 Silver Hill Road
Washington, DC 20233
Ph. (301) 278-9004
Link for an e-mail: Submit a Customer Service Request

** ***If*** *Cost Estimates* ***are*** re-assessed *and* re-computed *and yet found to be effectively the same as last year*, ***then*** *a statement to that effect has to be included with the Financial Assurance Report materials.*

♦Updated January 25, 2024♦

11228 Aurora Avenue
Des Moines, Iowa 50322-7905
United States
www.ghd.com

Our reference: 12574984-LTR-08

March 07, 2024

Mr. Josh Mohr
Environmental Director
MidAmerican Energy Company
4299 Northwest Urbandale Drive
Urbandale, Iowa 50322

Coal Combustion Residual Monofills – Asset Retirement Obligations

Dear Mr. Mohr:

1. Introduction and Certification

GHD prepared this letter and attachments to provide MidAmerican Energy Company (MidAmerican) with cost estimates for closure and post-closure of coal combustion residuals (CCR) Monofills (Monofills). These cost estimates address the Walter Scott, Jr. Energy Center (WSEC) CCR Monofill in Council Bluffs, Iowa; Louisa Generating Station (LGS) CCR Monofill in Muscatine, Iowa; and three CCR Monofill areas (Neal North Closed, Neal North Active, and Neal South) at the George Neal Energy Center in Salix, Iowa. The estimates were initially developed in accordance with the Financial Assurance requirements of Chapter 567—103.3, Iowa Administrative Code (IAC) for submittal to the Iowa Department of Natural Resources (IDNR) but have been adjusted to estimate closure at the end of the currently-permitted lifetime rather than at the most expensive point in closure. This serves as the appropriate timeframe for asset retirement obligations (AROs).

LICENSED PROFESSIONAL ENGINEER MICHAEL J. ALOWITZ 18160 IOWA	**I hereby certify that this engineering document was prepared by me or under my direct personal supervision and that I am a duly licensed Professional Engineer under the laws of the State of Iowa.** Michael J. Alowitz, P.E. — 3/7/24 Date **License Number:** 18160 **My license renewal date is:** December 31, 2024 **Pages or sheets covered by this seal:** Entire Document

1.1 Estimate Structure

General information about the current and projected conditions at the Monofills is provided in Section 2. Details in this letter are organized to include the components listed in subparagraphs 567—103.3(3)c(6) and 103.3(4)c(6), IAC. For each of the components listed, information is provided in Sections 3 and 4 of this letter to support the estimate.

1.2 Estimate Basis

The cost estimates have been prepared to address closure of the Monofills at the end of their permitted lifetime. The scope of the cost estimates only addresses the areas permitted for CCR disposal as of March 1, 2024. For example, at the LGS East Monofill, only Cells 1 through 3 are permitted for disposal although future cells are planned.

GHD prepared the estimates using several sources of data, including bid information for earthwork projects; verbal prices received from service providers; industry standard values; vendor prices lists; and projections for engineering or design services. The cost estimates are provided in 2024 dollars and are summarized in Table 1; supporting data are provided in Attachment A. Significant variables for future comparison include changes to permit requirements and changes to CCR production and recycling rates.

The format of these estimates, unit costs, and approach follows the previously-developed estimates for 567—103.3 IAC requirements, with the exception that a post-closure period of 30 years has been applied (except for the Neal North Closed Monofill), consistent with United States Environmental Protection Agency's (USEPA's) final rules for Disposal of CCRs from Electric Utilities (40 CFR Parts 257 and 261). The Neal North Closed Monofill has a closure period estimated at 10 years because it permitted by the State of Iowa and not currently subject to the federal CCR Rule.

1.3 2024 Updates

Significant changes from the 2023 evaluations include:

- An inflation factor of 1.026 has been applied to unit costs. The inflation factor is calculated using the gross domestic product implicit price deflator as required for the IDNR closure estimates. Inflation factor calculation information is provided in Attachment B.
- Lifetimes for Neal North, LGS, and WSEC Monofills have been updated based on the 2023 CCR placement volumes and recent filling rates.
- The number of monitoring wells to plug and abandon at the WSEC Monofill was updated.
- Post-closure costs for groundwater sampling and reporting were updated.
- For the Neal South Monofill, closed in 2018, the number of years remaining of post-closure has been reduced by 1.
- For the Neal North Closed Monofill, closed in 2010, but only permitted independently in 2021, the number of years remaining of post-closure has been reduced by 1.
- For the LGS West (closed) Monofill where the closure period started in 2022, the number of remaining years remaining of post-closure has been reduced by 1.
- For the Neal South closed Monofill, Corrective Measures have been updated to an annual cost and reduced to reflect the work completed to date.

1.4 2023 Placement Totals

The tonnage of material deposited in each Monofill, less materials removed for beneficial use in 2023, is as follows:

- WSEC Monofill, 230,214 tons placed
- LGS Monofill, 61,808 tons placed
- Neal North Monofill, 28,092 tons placed

2. Site Conditions

The Monofills included in this estimate are to be covered with a membrane cap. It is assumed MidAmerican will continue to complete partial capping activities as final grades are achieved. This has historically been completed at all three locations but has not yet been initiated on the currently active fill areas at Neal North or LGS.

2.1 WSEC Monofill

The WSEC Monofill is currently permitted for approximately 87 acres of Monofill footprint (Cells 1, 2, 3N, 3S, 4, 5, 6, 7, 8, and 9). The WSEC Monofill is a composite-lined facility. The final grades of the WSEC Monofill side slopes are up to 25 percent. The currently permitted WSEC Monofill is expected to reach capacity in 2048. Expansion cells or additional fill areas will likely be developed prior to closure.

2.2 LGS East (Active) Monofill

The LGS East Monofill is constructed with composite-lined cells. Cell 1 was completed in 2018 and Cells 2 and 3 were completed in 2019. The LGS East Monofill footprint is 11 acres.

The permitted capacity of the LGS East Monofill areas would last until 2025; however, an expansion will likely be completed prior to reaching permitted capacity.

2.3 LGS West (Closed) Monofill

The LGS West Monofill is in a bermed area with a footprint of approximately 34 acres and was closed in 2020. The LGS West Monofill was permitted independently of the LGS East Monofill in 2021. The LGS East Monofill is subject to the Federal CCR Rule. The first year of post-closure care is 2022 due to the permitting timeframe for separation from the LGS East Monofill.

2.4 Neal South Monofill

The Neal South Monofill covers approximately 32 acres. A composite cover was installed in 2018 including a 40-mil plastic liner with substantial construction completed in January 2019. The Neal South Monofill is closed, and closure costs are no longer applicable.

2.5 Neal North Active Monofill

The Neal North Active Monofill consists of composited-lined Cells 1 and 2 (13.6 acres). A total of three composite-lined cells are currently approved for construction at Neal North with a capacity projected to allow disposal until 2066.

2.6 Neal North Closed Monofill

The Neal North Closed Monofill consists of east and west fill areas (51 acres) where closure with an earthen cover system was completed in 2010. The Neal North Closed Monofill is regulated by the Iowa Department of Natural Resources and does not currently fall under the federal CCR rule. The first year of post-closure is considered 2021 because the closed monofill areas were previously included in the same Operating Permit as the Neal North Active Monofill.

3. Closure Costs

The required components of the closure cost estimates listed in subparagraph 567—103.3(3)c(6), IAC are presented below. Closure costs no longer apply to the Neal South Monofill and the Neal North Closed Monofill as closure construction is complete for these facilities.

3.1 Closure and Post-Closure Plan Document Revisions

These costs were estimated to be the same for WSEC, LGS, and Neal North Active Monofills. The scope of this component of the cost estimate includes a terrestrial survey, cap construction drawings, and closure and post-closure plan revisions.

3.2 Site Preparation, Earthwork, and Final Grading

Site grading and preparation can include consolidating CCR, modifying existing temporary capping, or associated site and site access grading. For this component of the cost estimate, GHD has assumed no off-site material will be brought on site and the cost components consist of excavating and recompacting material.

3.3 Drainage Control Culverts, Piping, and Structures

The actual drainage control culverts, piping, and structures would be evaluated at the time a final cap design is created. Currently, there are no calls for drainage piping or structures in the closure plans that would not have been installed during cell construction and operation.

3.4 Erosion Control Structures, Sediment Ponds, and Terraces

Erosion control structures, sediment ponds, and terraces will be determined during a final capping design. Stormwater terracing and channels are used in the current design for the Monofill caps. Costs for construction of the terraces and cap channels are included in the cap construction cost since much of the infrastructure will be installed during partial capping activities prior to closure.

3.5 Final Cap Construction

The proposed capping system at all three Monofills incorporates a geomembrane to limit permeability. The alternative cap at WSEC and the East LGS Monofill includes 6 inches of recompacted clay overlain by 60-mil high-density polyethylene (HDPE) geomembrane and drainage composite, overlain by a 12-inch topsoil layer. The proposed closure cap at the Neal North Active Monofill did not incorporate a membrane prior to a 2021 Operating Permit renewal but now includes a 40-mil linear low density (LLDPE) geomembrane, drainage layer, 18-inch layer of protective soil and a 6-inch topsoil layer. For Neal North, the earthen materials are available on-site or from adjacent parcels.

3.6 Cap Vegetation Soil Placement

It is assumed all topsoil for the vegetative soil layer will be imported for LGS and WSEC. For Neal North, local borrow is likely feasible based on a 2018 investigation of MidAmerican-owned parcels.

3.7 Cap Seeding, Mulching, and Fertilization

The same per-acre cost is assumed for the Monofill sites to address seeding, mulching, fertilizing, and establishment of vegetation on the final cap.

3.8 Monitoring Well and Piezometer Modifications

The monitoring well network at the four Monofill sites should not need modifications to accommodate capping activities because adequate monitoring networks are already installed or will be installed as part of any future expansion construction.

3.9 Leachate System Cleanout and Extraction Well Modifications

The WSEC, Neal North Active, and LGS East Monofills have leachate collection systems; however, the leachate extraction and clean-out piping are accessible outside the cells and no modifications to the piping are anticipated as part of closure activities.

3.10 Monitoring Well Installations and Abandonments

It is not anticipated that additional monitoring wells will be required as part of closure activities because an approved monitoring network is in place. Although some wells may be abandoned at the time of closure, it is more likely all surrounding monitoring wells will remain until the end of the post-closure period, 30 years after closure. Thus, no costs for new monitoring well installation or abandonment are included in the closure cost estimate.

3.11 Facility Modifications to Affect Closed Status

Facility modifications to affect closed status is assumed to include updating of signage to indicate the Monofill is closed and securing gates as necessary.

3.12 Engineering and Technical Services

Engineering and technical services during closure activities include construction oversight, documentation, and field testing. Since the scope of these activities is tied to the amount of earthwork, costs are calculated as a percentage of the estimated cost for completion of closure construction activities.

3.13 Legal, Financial, and Administrative Services

The scope of third-party legal, financial, and administrative services required to complete closure activities will vary by the entity, but includes adding a deed notation that the property was used as a CCR Monofill. To account for these costs, a uniform value has been applied to each Monofill project.

3.14 Closure Compliance Certifications and Documentation

The scope of closure compliance certifications and documentation includes providing the IDNR with assurance that the closure and construction activities have been completed in compliance with the permit. Documentation will likely include test results, construction photographs, and a signed engineer's statement attesting to completion of the closure activities. This category of the cost estimate is also expected to include updates to the IDNR during construction activities.

3.15 Corrective Measures for Groundwater

Under the federal CCR Rule, certain groundwater conditions may require implementation of corrective measures. None of the operating Monofills (Neal North Active, WSEC or LGS East) currently require corrective measures. The closed LGS West Monofill also does not require corrective measures, however, corrective measures have been implemented for the closed Neal South Monofill.

4. Post-Closure Costs

The required components of the post-closure cost estimates listed in subparagraph 567—103.3(4)c(6), IAC are presented below. The post-closure period is assumed to be 30 years (except for the Neal North Closed Monofill) to reflect federal regulations (40 CFR 257.104). 2024 represents year6 of post-closure of the Neal South Monofill (including 2024, there are 25 years of the post closure period), year 4 of post-closure for the Neal North Closed Monofill (7 years remaining of post-closure period), and year 3 of post closure for the LGS West Monofill (28 years of post-closure period remaining).

4.1 General Site Facilities, Access Roads, and Fencing Maintenance

During the post-closure period, site access roads must be maintained to permit cap maintenance. Site control through fencing must also be maintained. The amount of maintenance required will vary from site to site and is dependent on weather and adjacent site activities. A maintenance allowance has been allotted for each year of the post-closure period; however, the actual annual maintenance activities and costs are expected to vary.

4.2 Cap and Vegetative Cover Maintenance

Erosion of the cap must be monitored during the post-closure period and damage repaired. An allowance has been made for annual repair; however, the scope of maintenance activities will be highly dependent on-site conditions and activities.

4.3 Drainage and Erosion Control System Maintenance

Maintenance of a drainage and erosion control system may include removing soil or vegetation from drainageways, replacing riprap, or other erosion control methods. As with other maintenance activities, the actual scope of required work will be highly variable and a maintenance allowance has been made in the cost estimates.

4.4 Groundwater-to-Waste Separation Systems Maintenance

4.4.1 WSEC Monofill

During construction of Cells 1 and 2 at the WSEC Monofill, high groundwater conditions were observed that are believed to be anomalous. The IDNR stated if the high groundwater conditions were not anomalous, then MidAmerican would have to complete active measures to maintain the minimum 5-foot separation distance between the CCR in the Monofill and high groundwater elevation. The base was raised in the design of subsequent cells. At this time, it is not anticipated any active system will be required to maintain the groundwater-to-waste separation distance at the WSEC Monofill.

4.4.2 Neal North Active, Neal North Closed, Neal South, LGS East, and LGS West Monofills

Based on site conditions at these facilities, no costs are allocated for maintenance or operation of a groundwater-to-waste separation system.

4.5 Groundwater and Surface Water Monitoring Systems Maintenance

Maintenance of monitoring wells may include installation of replacement wells, replacement of protective casings, grading around wells, or surveying. To account for the possibility of these maintenance activities, an annual allowance has been made in the cost estimate. There is no surface water sampling requirement in the current IDNR-approved monitoring networks for any of the listed facilities.

At the conclusion of the post-closure period, monitoring wells will be abandoned. Costs for well abandonment at the end of the post-closure period are included in another component of the cost estimate.

For the Neal North Closed Monofill, it is assumed that monitoring wells will remain in place after the post-closure period because they may continue to provide valuable data to other adjacent or overlapping monitoring works. The annual allowance for monitoring well repairs at the Neal North Closed Monofill is also significantly less because much of the network is associated with other monitoring networks where repair costs are accounted for. For the 2024 estimates, 3 additional monitoring wells were added to the total for the WSEC Monofill.

4.6 Groundwater and Surface Water Quality Monitoring and Reports

Annual groundwater sampling and reporting are required during the post-closure period. GHD has estimated this cost using current sampling and reporting costs and to reflect monitoring of both the existing and future Monofill areas at LGS.

Monitoring programs for all four Monofills have been amended in the operating permit to reflect the federal monitoring requirements. Post-closure groundwater monitoring will be conducted semiannually.

4.7 Groundwater Monitoring Systems Performance Evaluations and Reports

Evaluations of the groundwater monitoring systems are included in the annual water quality monitoring report and no additional costs are allocated.

4.8 Leachate Control Systems Maintenance

The WSEC, Neal North Active, and LGS East Monofills have leachate collection systems that will remain in operation during closure and post-closure. Video logging of the collection and extraction pipes at WSEC has shown no cleaning efforts are required after over a decade of operation. Due to the nature of the CCR, it is anticipated some mineral scaling may occur, but not to the point of requiring significant cleaning due to low quantities of leachate and large, 8-inch-diameter laterals. As operational data become available in future years, these assumptions may be revised.

The small-scale leachate collection system at Neal South is anticipated to remain in place during a portion of the closure period but have minimal operation requirements.

The LGS West Monofill and Neal North Closed Monofill do not include a leachate control system.

4.9 Leachate Management, Transportation, and Disposal

4.9.1 WSEC Monofill

Upon closure, there will be approximately 88 acres requiring leachate management. An annual allowance has been made for costs associated with extraction, transportation, and treatment of 1,500,000 gallons of leachate. Previously, 2,400,000 gallons were used as the annual estimate; however, the assumed average rate for the 30-year period was lowered for 2016 to 1,500,000 gallons due to decreased rates of leachate generation in post-closure years. The City of Council Bluffs Wastewater Treatment Plant, located north of the Monofill, will accept the leachate.

4.9.2 Neal North Monofill

Upon closure, Cells 1, 2, and 3 will require leachate management. In 2018, a leachate pond was constructed at Neal North. The estimate reflects hauling 500,000 gallons of leachate to the City of Sioux City Wastewater Treatment Plant annually.

4.9.3 Neal South Monofill

A small-scale leachate collection system is currently in use at the Neal South Monofill. For the purposes of estimating ongoing post-closure costs, it is assumed the system will be abandoned prior to final closure. Costs have been included for collecting and hauling leachate to the Neal North leachate pond and for abandonment in place of the collection system.

4.9.4 LGS East Monofill

The LGS East Monofill includes a leachate collection system and thus, costs are included for managing leachate at LGS.

4.10 Leachate Control Systems Performance Evaluations and Reports

An annual report of leachate production and management system performance is required during the post-closure period. The data for assessment of the control system would be acquired during the leachate management, transportation, and disposal operations. Additional costs are allocated to prepare the annual leachate system performance evaluation.

4.11 Facility Inspections and Reports

An annual engineering inspection of the completed cap is required. The engineering inspection will be documented in a report to the IDNR. The inspection typically consists of visual observation of the cover and noted apparent deficiencies in the cap thickness, erosion patterns, or areas where vegetation is not established.

4.12 Engineering and Technical Services

An annual allowance for engineering and technical services has been made in the cost estimate. The scope of engineering services during the post-closure period will likely be limited to support for any permit modifications or changes to erosion control features. Additional services such as groundwater sampling or the annual engineering inspection are included in other components of the cost estimate.

4.13 Legal, Financial, and Administrative Services

The scope of third-party legal, financial, and administrative services required to complete closure activities will vary by the entity. To account for these costs, a uniform value has been applied to each of the four Monofill projects.

4.14 Financial Assurance, Accounting, Audits, and Reports

The costs of third-party financial assurance, accounting, audits, and reports are difficult to assess because the requirements may vary from site to site. To account for these costs, a uniform value has been applied for each year of the post-closure period.

4.15 Corrective Measures for Groundwater

Under the federal CCR Rule, certain groundwater conditions may require implementation of corrective measures. The Neal South Monofill, which is in the post-closure period, was identified for implementation of corrective measures. Corrective measures are initiated at the Neal South Monofill in 2020 and the additional noted costs reflect a remaining 4-year period of monitoring and reporting.

Regards,

Michael J. Alowitz

Michael J. Alowitz, P.E.
Senior Engineer

515 414-3934
michael.alowitz@ghd.com

Kevin G. Armstrong

Kevin G. Armstrong, C.P.G., P.M.P.
Project Manager

515 414-3935
kevin.armstrong@ghd.com

MA/lg/LTR-08

Encl.

Copy to: Josh Love, MidAmerican

Tables

Table 1

Summary of Asset Retirement Obligations
MidAmerican Energy Company
Coal Combustion Residue Monofills
March 2024

	NN Active	NN Closed	Neal South	WSEC	LGS-West	LGS-East	TOTAL
Closure Year	2066	Closed	Closed	2048	Closed	2025	
Initiated Post-Closure	Active	2021	2019	Active	2022	Active	
Total Dollars							
Current Closure Cost	$1,632,000	-	-	$9,617,000	-	$1,522,000	
Current Post-Closure Cost	$4,445,000	$495,000	$3,237,000	$15,980,000	$2,668,000	$3,772,000	
Total Dollar Value	$6,077,000	$495,000	$3,237,000	$25,597,000	$2,668,000	$5,294,000	
Total (All Four Facilities)							**$43,368,000**
Total (All Facilities)							

Notes:
Supporting calculations provided on additional sheets.
NN - Neal North
WSEC - Walter Scott, Jr. Energy Center.
LGS - Louisa Generating Station.

Post-closure costs assume a 30-year post-closure period except for NN Closed.

Attachments

Attachment A

Cost Estimate Supporting Calculations

Neal North Active CCR Monofill
ARO Closure and Post-Closure Cost Estimate
March 2024

		Unit	Unit Cost	Quantity	Total
CLOSURE					
1	Closure and Post-Closure (C/PC) Plan document revisions.				
	C/PC Plan, Hydrologic Monitoring System Plan (HMSP)	Lump	$55,368	1	$55,368
	Survey	Lump	$16,610	1	$16,610
2	Site preparation, earthwork, and final grading.				
	Grading	CY	$6.10	2,000	$12,206
	Coal Combustion Residue (CCR) Grading	CY	$4.97	5,000	$24,829
3	Drainage control culverts, piping, and structures.	Lump	$0	0	$0
4	Erosion control structures, sediment ponds, and terraces.	Lump	$0	0	$0
5	Final cap construction.	CY	$13.07	12,100	$158,144
	60-mil HDPE and drainage Layer	SF	$3.44	239,580	$823,079
6	Cap vegetation soil placement.	CY	$11.88	4,033	$47,922
	Mobilization/Appurtenant Work (percent of earthwork)	Percent	5%	1	$53,309
7	Cap seeding, mulching, and fertilization.	Acre	$5,689	20	$113,788
8	Monitoring well and piezometer modifications.	Lump	$0	0	$0
9	Leachate system cleanout and extraction well modifications.	Lump	$0	0	$0
10	Monitoring well installations and abandonments.	Lump	$0	0	$0
11	Facility modifications to effect closed status.	Lump	$3,216	1	$3,216
12	Engineering and technical services (percent of earthwork).	Percent	15%	1	$184,992
13	Legal, financial, and administrative services.	Lump	$69,210	1	$69,210
14	Closure compliance certifications and documentation.	Lump	$69,210	1	$69,210
15	Corrective measures for groundwater.	Lump	$0	0	$0
			Closure Subtotal		**$1,631,885**
30 YEAR POST CLOSURE					
1	General site facilities, access roads, and fencing maintenance.	Annual	$6,921	30	$207,631
2	Cap and vegetative cover maintenance.	Annual	$6,921	30	$207,631
3	Drainage and erosion control system maintenance.	Annual	$2,768	30	$83,052
4	Groundwater to waste separation systems maintenance.	Annual	$0	0	$0
5	Groundwater and surface water monitoring systems maintenance.				
	Annual Allowance for Repairs	Annual	$1,384	30	$41,526
	Well Abandonment	Well (one-time)	$831	33	$27,407
6	Groundwater/surface water quality gauging and sampling.	Semiannual	$6,500	60	$390,000
7	Groundwater/surface water evaluations and reports.	Annual	$23,000	30	$690,000
8	Leachate control systems maintenance.	Annual	$6,785	30	$203,541
9	Leachate management, transportation, and disposal.	Annual	$33,861	30	$1,015,830
10	Leachate control systems performance evaluations and reports.	Annual	$5,536	30	$166,090
11	Facility inspections and reports.	Annual	$5,537	30	$166,104
12	Engineering and technical services.	Annual	$13,842	30	$415,261
13	Legal, financial, and administrative services.	Annual	$13,842	30	$415,261
14	Financial assurance, accounting, audits, and reports.	Annual	$13,842	30	$415,261
15	Corrective measures for groundwater.	Lump	$0	0	$0
			Post-Closure Subtotal		**$4,444,596**

Notes:
Start date for financial calculations is March 1, 2024.

Neal North Closed CCR Monofill
Closure and Post-Closure Cost Estimate
March 2024

		Unit	Unit Cost	Quantity	Total
10 YEAR POST CLOSURE (CURRENT PERMIT)					
1	General site facilities, access roads, and fencing maintenance.	Annual	$6,921	7	$48,447
2	Cap and vegetative cover maintenance.	Annual	$6,921	7	$48,447
3	Drainage and erosion control system maintenance.	Annual	$2,768	7	$19,379
4	Groundwater to waste separation systems maintenance.	Annual	$0	0	$0
5	Groundwater and surface water monitoring systems maintenance.				
	Annual Allowance for Repairs	Annual	$346	7	$2,424
	Well Abandonment	Well (one time)	$0	0	$0
6	Groundwater/surface water quality gauging and sampling.	Semiannual	$7,000	14	$98,000
7	Groundwater/surface water evaluations and reports.	Annual	$17,000	7	$119,000
8	Leachate control systems maintenance.	Annual	$0	0	$0
9	Leachate management, transportation, and disposal.	Annual	$0	0	$0
10	Leachate control systems performance evaluations and reports.	Annual	$0	0	$0
11	Facility inspections and reports.	Annual	$5,468	7	$38,275
12	Engineering and technical services.	Annual	$5,772	7	$40,405
13	Legal, financial, and administrative services.	Annual	$5,772	7	$40,405
14	Financial assurance, accounting, audits, and reports.	Annual	$5,772	7	$40,405
15	Corrective measures for groundwater.	Lump	$0	0	$0
			Post-Closure Subtotal		**$495,189**

Notes:
Start date for financial calculations is March 1, 2024.

Neal South CCR Monofill
ARO Closure and Post-Closure Cost Estimate
March 2024

		Unit	Unit Cost	Quantity	Total
30 YEAR POST CLOSURE					
1	General site facilities, access roads, and fencing maintenance.	Annual	$6,921	25	$173,025
2	Cap and vegetative cover maintenance.	Annual	$6,921	25	$173,025
3	Drainage and erosion control system maintenance.	Annual	$2,768	25	$69,210
4	Groundwater to waste separation systems maintenance.	Annual	$0	0	$0
5	Groundwater and surface water monitoring systems maintenance.				
	Annual Allowance for Repairs	Annual	$1,384	25	$34,605
	Well Abandonment	Well (one-time)	$817	52	$42,507
6	Groundwater/surface water quality gauging and sampling.	Semiannual	$20,000	50	$1,000,000
7	Groundwater/surface water evaluations and reports.	Annual	$18,000	25	$450,000
8	Leachate control systems maintenance (abandon).	Lump (once)	$2,376	1	$2,376
9	Leachate management, transportation, and disposal.	Annual	$4,753	3	$14,258
10	Leachate control systems performance evaluations and reports.	Annual	$1,237	3	$3,712
11	Facility inspections and reports.	Annual	$5,537	25	$138,420
12	Engineering and technical services.	Annual	$13,842	25	$346,051
13	Legal, financial, and administrative services.	Annual	$13,842	25	$346,051
14	Financial assurance, accounting, audits, and reports.	Annual	$13,842	25	$346,051
15	Corrective measures for groundwater.	Annual	$32,719	3	$98,157
			Post-Closure Subtotal		**$3,237,450**

Notes:
Start date for financial calculations is March 1, 2024.

Louisa Generating Station West (Closed) CCR Monofill
ARO Closure and Post-Closure Cost Estimate
March 2024

		Unit	Unit Cost	Quantity	Total
30 YEAR POST CLOSURE					
1	General site facilities, access roads, and fencing maintenance.	Annual	$6,921	28	$193,789
2	Cap and vegetative cover maintenance.	Annual	$6,921	28	$193,789
3	Drainage and erosion control system maintenance.	Annual	$2,768	28	$77,515
4	Groundwater to waste separation systems maintenance.	Annual	$0	0	$0
5	Groundwater and surface water monitoring systems maintenance.				
	Annual Allowance for Repairs	Annual	$1,384	28	$38,758
	Well Abandonment	Well (one-time)	$817	8	$6,540
6	Groundwater/surface water quality gauging and sampling.	Semiannual	$6,500	56	$364,000
7	Groundwater/surface water evaluations and reports.	Annual	$17,000	28	$476,000
8	Leachate control systems maintenance.	Annual	$0	28	$0
9	Leachate management, transportation, and disposal.	Annual	$0	28	$0
10	Leachate control systems performance evaluations and reports.	Annual	$0	28	$0
11	Facility inspections and reports.	Annual	$5,537	28	$155,031
12	Engineering and technical services.	Annual	$13,842	28	$387,577
13	Legal, financial, and administrative services.	Annual	$13,842	28	$387,577
14	Financial assurance, accounting, audits, and reports.	Annual	$13,842	28	$387,577
15	Corrective measures for groundwater.	Lump	$0	0	$0
			Post-Closure Subtotal		**$2,668,152**

Notes:
Start date for financial calculations is March 1, 2024.

Louisa Generating Station East (Active) CCR Monofill
ARO Closure and Post-Closure Cost Estimate
March 2024

		Unit	Unit Cost	Quantity	Total
CLOSURE					
1	Closure and Post-Closure (C/PC) Plan document revisions.				
	C/PC Plan, Hydrologic Monitoring System Plan (HMSP)	Lump	$55,368	1	$55,368
	Survey	Lump	$16,610	1	$16,610
2	Site preparation, earthwork, and final grading.				
	Grading	CY	$10.51	5,000	$52,536
	Coal Combustion Residue (CCR) Grading	CY	$4.97	3,000	$14,897
3	Drainage control culverts, piping, and structures.	Lump	$49,495	0	$0
4	Erosion control structures, sediment ponds, and terraces.	Lump	$0	0	$0
5	Final cap construction.	CY	$13.07	10,000	$130,697
	60-mil HDPE and drainage Layer	SF	$4.04	184,000	$743,460
6	Cap vegetation soil placement.	CY	$16.37	7,000	$114,561
	Mobilization/Appurtenant Work (percent of earthwork)	Percent	5%	1	$52,808
7	Cap seeding, mulching, and fertilization.	Acre	$5,689	5	$28,447
8	Monitoring well and piezometer modifications.	Lump	$0	0	$0
9	Leachate system cleanout and extraction well modifications.	Lump	$0	0	$0
10	Monitoring well installations and abandonments.	Lump	$0	0	$0
11	Facility modifications to effect closed status.	Lump	$3,216	1	$3,216
12	Engineering and technical services (percent of earthwork).	Percent	15%	1	$170,611
13	Legal, financial, and administrative services.	Lump	$69,210	1	$69,210
14	Closure compliance certifications and documentation.	Lump	$69,210	1	$69,210
15	Corrective measures for groundwater.	Lump	$0	0	$0
			Closure Subtotal		**$1,521,631**
30 YEAR POST CLOSURE					
1	General site facilities, access roads, and fencing maintenance.	Annual	$6,921	30	$207,631
2	Cap and vegetative cover maintenance.	Annual	$6,921	30	$207,631
3	Drainage and erosion control system maintenance.	Annual	$2,768	30	$83,052
4	Groundwater to waste separation systems maintenance.	Annual	$0	0	$0
5	Groundwater and surface water monitoring systems maintenance.				
	Annual Allowance for Repairs	Annual	$1,384	30	$41,526
	Well Abandonment	Well (one-time)	$817	15	$12,262
6	Groundwater/surface water quality gauging and sampling.	Semiannual	$7,500	60	$450,000
7	Groundwater/surface water evaluations and reports.	Annual	$17,000	30	$510,000
8	Leachate control systems maintenance.	Annual	$6,071	30	$182,145
9	Leachate management, transportation, and disposal.	Annual	$18,561	30	$556,816
10	Leachate control systems performance evaluations and reports.	Annual	$3,643	30	$109,287
11	Facility inspections and reports.	Annual	$5,537	30	$166,104
12	Engineering and technical services.	Annual	$13,842	30	$415,261
13	Legal, financial, and administrative services.	Annual	$13,842	30	$415,261
14	Financial assurance, accounting, audits, and reports.	Annual	$13,842	30	$415,261
15	Corrective measures for groundwater.	Lump	$0	0	$0
			Post-Closure Subtotal		**$3,772,236**

Notes:
Start date for financial calculations is March 1, 2024.

Walter Scott, Jr. Energy Center CCR Monofill
ARO Closure and Post-Closure Cost Estimate
March 2024

		Unit	Unit Cost	Quantity	Total
CLOSURE					
1	Closure and Post-Closure (C/PC) Plan document revisions.				
	C/PC Plan, Hydrologic Monitoring System Plan (HMSP)	Lump	$55,368	1	$55,368
	Survey	Lump	$16,610	1	$16,610
2	Site preparation, earthwork, and final grading.				
	Grading	CY	$9.00	5,000	$44,987
	Coal Combustion Residue (CCR) Grading	CY	$14.38	5,000	$71,924
3	Drainage control culverts, piping, and structures.	Lump	$0	0	$0
4	Erosion control structures, sediment ponds, and terraces.	Lump	$0	0	$0
5	Final cap construction.	acres	$249,513	30	$7,485,393
6	Cap vegetation soil placement (included line 5).				
	Mobilization/Appurtenant Work (percent of earthwork)	Percent	5%	1	$380,115
7	Cap seeding, mulching, and fertilization.	Acre	$5,545	35	$194,084
8	Monitoring well and piezometer modifications.	Lump	$0	0	$0
9	Leachate system cleanout and extraction well modifications.	Lump	$0	0	$0
10	Monitoring well installations and abandonments.	Lump	$0	0	$0
11	Facility modifications to effect closed status.	Lump	$3,216	1	$3,216
12	Engineering and technical services (percent of earthwork).	Percent	15%	1	$1,226,475
13	Legal, financial, and administrative services.	Lump	$69,210	1	$69,210
14	Closure compliance certifications and documentation.	Lump	$69,210	1	$69,210
15	Corrective measures for groundwater.	Lump	$0	0	$0
			Closure Subtotal		**$9,616,592**
30 YEAR POST CLOSURE					
1	General site facilities, access roads, and fencing maintenance.	Annual	$6,921	30	$207,631
2	Cap and vegetative cover maintenance.	Annual	$6,921	30	$207,631
3	Drainage and erosion control system maintenance.	Annual	$2,768	30	$83,052
4	Groundwater to waste separation systems maintenance.	Annual	$0	0	$0
5	Groundwater and surface water monitoring systems maintenance.				
	Annual Allowance for Repairs	Annual	$1,384	30	$41,526
	Well Abandonment	Well (one-time)	$831	32	$26,577
6	Groundwater/surface water quality gauging and sampling.	Semiannual	$7,500	60	$450,000
7	Groundwater/surface water evaluations and reports.	Annual	$17,000	30	$510,000
8	Leachate control systems maintenance.	Annual	$6,711	30	$201,327
9	Leachate management, transportation, and disposal.	Annual	$422,471	30	$12,674,126
10	Leachate control systems performance evaluations and reports.	Annual	$5,536	30	$166,090
11	Facility inspections and reports.	Annual	$5,537	30	$166,104
12	Engineering and technical services.	Annual	$13,842	30	$415,261
13	Legal, financial, and administrative services.	Annual	$13,842	30	$415,261
14	Financial assurance, accounting, audits, and reports.	Annual	$13,842	30	$415,261
15	Corrective measures for groundwater.	Lump	$0	0	$0
			Post-Closure Subtotal		**$15,979,846**

Notes:
Start date for financial calculations is March 1, 2024.

Attachment B

Inflation Factor

The 'Inflation Factor'– 2023 over 2022
for Landfill Financial Assistance Cost Estimates

Ref. Iowa Admin. Code [567] sub-sections (3), (4) & (5) in each of sections 113.14, 115.31, 114.31 & 103.3

Every Annual Financial Assurance Report must UPDATE Closure, Postclosure &/or Corrective Action Cost Estimates, **IN CURRENT DOLLARS**, certified by an Iowa-licensed professional engineer.

IF no other re-assessment/computations are done**, Cost Estimates HAVE TO **AT LEAST** BE adjusted for annual inflation By **multiplying** last year's Cost Estimates **times** the **Inflation Factor**.

As of *January 25, 2024*, the Inflation Factor for this year's Financial Assurance Reports is **1.026**

as Derived from Gross Domestic Product statistics, using the formula:

Implicit Price Deflator of most recent quarter ÷ Implicit Price Deflator of previous year's same corresponding quarter	= **Inflation Factor**

Find the Implicit Price Deflators for GROSS DOMESTIC PRODUCT at this website
of the U.S. Dept. of Commerce, Bureau of Economic Analysis (BEA):
https://apps.bea.gov/iTable/?reqid=19&step=3&isuri=1&1921=survey&1903=13

So it is then that:

$$\frac{\text{20}\mathbf{23}\ 4^{th}\text{ quarter implicit price deflator}}{\text{20}\mathbf{22}\ 4^{th}\text{ quarter implicit price deflator}} = \textbf{Inflation Factor}$$

$$\frac{\mathbf{123.226}}{\mathbf{120.093}} = \mathbf{1.026}$$

*as An **Example***, ---with No other re-assessment/re-computations** being made…
IF, Last *Year's combined Cost Estimates* = **$2,000,000**
Applying this year's Inflation Factor then *means*:
$2,000,000* X 1.026 = *$2,052,000
i.e. This Year's updated combined Cost Estimates adjusted for inflation.

Source of the Implicit Price Deflators for **GROSS DOMESTIC PRODUCT**:

U.S. Department of Commerce
Bureau of Economic Analysis (BEA)
4600 Silver Hill Road
Washington, DC 20233
Ph. (301) 278-9004
Link for an e-mail: Submit a Customer Service Request

** ***If*** *Cost Estimates* ***are*** re-assessed *and* re-computed *and yet found to be effectively the same as last year,* ***then*** *a statement to that effect has to be included with the Financial Assurance Report materials.*

♦Updated January 25, 2024♦

11228 Aurora Avenue
Iowa 50322-7905
United States
www.ghd.com

Our reference: 12574984-LTR-09

March 07, 2024

Mr. Josh Mohr
Environmental Director
MidAmerican Energy Company
4299 Northwest Urbandale Drive
Urbandale, Iowa 50322

Coal Combustion Residual Impoundments
Closure and Post-Closure Cost Estimates for Permitting

Dear Mr. Mohr:

1. Introduction and Certification

GHD prepared this letter and attachments to provide MidAmerican Energy Company (MidAmerican) with cost estimates for closure and post-closure of inactive coal combustion residuals (CCR) impoundments (Impoundments) in accordance with the Financial Assurance requirements of Chapter 567—103.3, Iowa Administrative Code (IAC). These cost estimates address the Louisa Generating Station (LGS) Bottom Ash Impoundment (Permit No. 70-SDP-23-18C), Walter Scott, Jr. Energy Center (WSEC) North and South Impoundments in Council Bluffs, Iowa (Permit #78-SDP-33-16C) and Impoundments 1, 2, 3A, and 3B at the George Neal Energy Center - North in Salix, Iowa (Neal North, Permit #97-SDP-22-16C).

Significant changes from the 2023 evaluations include:

- Application of an inflation factor of 1.026 to unit prices for post-closure care.
- Significant completion of WSEC North-South Impoundment closure with only administrative activities remaining.
- Post-closure costs for groundwater sampling and reporting were updated.
- Costs associated with corrective measures for groundwater were added.

LICENSED PROFESSIONAL ENGINEER MICHAEL J. ALOWITZ 18160 IOWA	**I hereby certify that this engineering document was prepared by me or under my direct personal supervision and that I am a duly licensed Professional Engineer under the laws of the State of Iowa.**
	Michael J. Alowitz, P.E. — Date: 3/7/24
	License Number: 18160
	My license renewal date is: December 31, 2024
	Pages or sheets covered by this seal: Entire Document

1.1 Estimate Structure

General information about the current and projected conditions at the Impoundments is provided in Section 2. Details in this letter are organized to include the components listed in subparagraphs 567-103.3(3)c(6) and 103.3(4)c(6), IAC. For each of the components listed, information is provided in Sections 3 and 4 of this letter to support the estimate.

1.2 Estimate Basis

These cost estimates have been prepared to address closure and post-closure care of the Impoundments in accordance with permit documents. The estimates are to be revised by MidAmerican annually to allow for inflation. At the time of a Permit Amendment, the cost estimates are to be revised. Changes to closure, closure permits, state or federal requirements, or post-closure experiences may affect the future cost estimates.

GHD prepared the estimates using several sources of data, including bid information for earthwork projects; verbal prices received from service providers; industry standard values; vendor price lists, and projections for engineering or design services. The cost estimates are provided in 2024 dollars and are summarized in Table 1; supporting data are provided in Attachment A.

2. Site Conditions

2.1 Neal North Impoundments 1, 2, 3A, and 3B

An updated closure permit was issued by the IDNR on February 18, 2020 that incorporated consolidation of CCR from Impoundments 1, 2, 3A, and 3B. Impoundments 1, 2, and 3A were originally closed in 2016 and 2017; however, the revised closure permit reset the post-closure timeline. In 2022, removal of CCR from Impoundments 1, 2, 3A, and 3B and consolidation of the material above the high-water table level within the footprint of Impoundment 3B was completed in 2022. The post-closure period was initiated in 2023.

A portion of Impoundment 1 was previously closed by removal of CCR and a leachate pond and process water pond were constructed in the space. The leachate and process water ponds are not included in these closure estimates because they are not part of the CCR Impoundment system.

2.2 WSEC North and South Impoundments

The WSEC North and- South Impoundment include approximately 276 acres where the presence of CCR was confirmed. Investigation of other dry portions of the impoundment footprints confirmed the absence of CCR. The impoundments are separated by Pony Creek. To the west of the North Impoundment is the Mosquito Creek levee. The other surrounding perimeter are embankments supporting local access roads. The approved closure plan includes removal and consolidation of CCR from potentially saturated conditions. The recovered CCR and dry-area CCR were consolidated and covered with a 40-mil linear low-density polyethylene (LLDPE) liner and earthen protective surface.

Closure construction was initiated in 2019 and the construction work was completed in 2023. was Final documentation and reporting work remains to be completed. Therefore, the post-closure period has not been initiated for the impoundments. It is anticipated a final closure permit will be issued in 2024.

2.3 LGS Impoundment

The LGS Impoundment formerly consisted of an approximately 30-acre bottom ash impoundment and a 4-acre polishing basin. The polishing basin was removed from service in 2017 and CCR along with underlying liner material was excavated to complete closure by removal. In 2018, closure construction on the LGS bottom ash impoundment was initiated, including grading of CCR and development of closure support structures like drainage channels and a stormwater pond. Closure was completed in 2020 and the post-closure period effectively started in 2021.

3. Closure Costs

Applicable required components of the closure cost estimates listed in subparagraph 567—103.3(3)c(6), IAC are presented below. Closure costs for the WSEC North and South Impoundments are estimated in Table 1 and Attachment A. All closure construction work is complete with only certifications and documentation remaining. Closure work at other impoundments is complete and the post-closure period has started; therefore, no closure costs are included for the LGS Impoundment or Neal North Impoundments 1, 2, 3A, and 3B. Cost items in 567—103.3(3)c(6), IAC that are not applicable are not included.

3.1 Closure and Post-Closure Plan Document Revisions

Closure Plans are approved for the WSEC Impoundments; thus, there is no cost associated with this item.

3.2 Site Preparation, Earthwork, and Final Grading

All site preparation, earthwork, and final grading are complete; thus, there is no cost associated with this item.

3.3 Drainage Control Culverts, Piping, and Structures

All drainage improvements are complete, thus, there is no cost associated with this item.

3.4 Erosion Control Structures, Sediment Ponds, and Terraces

All erosion control construction is complete, thus, there is no cost associated with this time.

3.5 Final Cap Construction

Final cap construction is complete; thus, there is no cost associated with this item.

3.6 Cap Vegetation Soil Placement

Cap vegetation soil placement is complete, thus, there is no cost associated with this item.

3.7 Cap Seeding, Mulching, and Fertilization

Cap seeding, mulching, and fertilization is complete; thus, there is no cost associated with this item.

3.8 Monitoring Well and Piezometer Modifications

No modifications to monitoring wells or piezometers are necessary; therefore, there is no cost associated with this item.

3.9 Monitoring Well Installations and Abandonments

All monitoring wells associated with the impoundments were installed; thus, there is no cost associated with this item.

3.10 Facility Modifications to Affect Closed Status

No additional facility modifications to affect closed status are required; thus, there is no cost associated with this item.

3.11 Engineering and Technical Services

Since construction is complete, there are no further engineering and technical services associated with closure construction. There is no cost associated with this item.

3.12 Legal, Financial, and Administrative Services

Administrative services required to complete closure activities such as adding a deed notation that a former impoundment is located on the property are complete. There is no cost associated with this item.

3.13 Closure Compliance Certifications and Documentation

Final closure documentation to the Iowa Department of Natural Resources (IDNR) with test results, construction photographs, and a signed engineer's statement attesting to completion of the closure activities is pending. The final step to complete closure is IDNR acceptance of this report and issuance of an updated permit.

4. Post-Closure Costs

The applicable components of the post-closure cost estimates listed in subparagraph 567—103.3(4)c(6), IAC are presented below. The post-closure period is 30 years. The post-closure period for the LGS Impoundment started in 2021; there are 27 years remaining of post-closure care, including 2024. The post closure period for the Neal North Impoundments started in 2024; there are 29 years remaining of post-closure care.

4.1 General Site Facilities, Access Roads, and Fencing Maintenance

During the post-closure period, site access roads must be maintained to permit cover system maintenance. Site control through fencing must also be maintained. The amount of maintenance required will vary from year to year and is dependent on weather and adjacent site activities. A maintenance allowance has been allotted for each year of the post-closure period; however, the actual annual maintenance activities and costs are expected to vary.

4.2 Cap and Vegetative Cover Maintenance

Erosion of the cover system must be monitored during the post-closure period and any damage repaired. An allowance has been made for annual repair; however, the scope of maintenance activities will be highly dependent on-site conditions and activities. This item also includes mowing the vegetated cap.

4.3 Drainage and Erosion Control System Maintenance

Maintenance of a drainage and erosion control system may include removing soil or vegetation from drainage ways, replacing riprap, or other erosion control methods. As with other maintenance activities, the actual scope of required work will be highly variable and a maintenance allowance has been made in the cost estimates.

4.4 Groundwater Monitoring Systems Performance Evaluations

Maintenance of monitoring wells may include installation of replacement wells, replacement of protective casings, grading around wells, or surveying. To account for the possibility of these maintenance activities, an annual allowance has been made in the cost estimate.

At the conclusion of the post-closure period, monitoring wells will be abandoned. Costs for well abandonment at the end of the post-closure period are included in this component of the cost estimate. At WSEC and Neal North, it is assumed monitoring wells that are likely to continue to support Monofill monitoring activities will remain after the impoundment post-closure period has ended. Two additional monitoring wells were added for the WSEC impoundments in the current estimate.

4.5 Groundwater and Surface Water Quality Monitoring and Reports

Semiannual groundwater sampling and annual reporting are required during the post-closure period. This estimate assumes the current monitoring network and protocols remain in effect. There is no surface water monitoring included in the current monitoring plans at any of the sites. Neal North impoundments 1, 2, and 3A and WSEC South Impoundment closed by removal may be removed from the monitoring plan prior to 30 years of post-closure monitoring, however, the LGS impoundment and the consolidated CCR in Neal North Impoundment 3B and WSEC North impoundments will be subject to a 30-year post closure monitoring period.

4.6 Facility Inspections and Reports

An annual engineering inspection of the completed cap is required. The engineering inspection will be documented in a report to the IDNR. The inspection typically consists of visual observation of the cover and noted apparent deficiencies in the cap thickness, erosion patterns, or areas where vegetation is not established.

4.7 Engineering and Technical Services

An annual allowance for engineering and technical services has been made in the cost estimate. The scope of engineering services during the post-closure period will likely be limited to support for any permit modifications or changes to erosion control features. Additional services such as groundwater sampling or the annual engineering inspection are included in other components of the cost estimate.

4.8 Legal, Financial, and Administrative Services

The scope of third-party legal, financial, and administrative services required to complete closure activities will vary by the entity. To account for these costs, a uniform value has been applied to each facility.

4.9 Financial Assurance, Accounting, Audits, and Reports

The costs of third-party financial assurance, accounting, audits, and reports are difficult to assess because the requirements may vary from entity to entity. To account for these costs, a uniform value has been applied for each year of the post-closure period.

4.10 Corrective Measures

Under the federal CCR Rule, certain groundwater conditions may require implementation of corrective measures. The Neal South Monofill, which is in the post-closure period, was identified for implementation of corrective measures. As of March 1, 2024, corrective measures are underway at the Neal North impoundments and identified as required for the WSEC North Impoundment. The final scope of these measures is not determined; costs are estimated for initial delineation and assessment activities (where not already completed) and additional groundwater monitoring and reporting for a period of five years. Some corrective measures have been selected for the Neal North impoundments, but the selection phase has not been reached for WSEC North Impoundment.

Regards,

Michael J. Alowitz, P.E.
Senior Engineer

+1 515 414-3934
michael.alowitz@ghd.com

Kevin Armstrong, C. P.G., P.M.P.
Project Manager

+1 515 414-3935
kevin.armstrong@ghd.com

MA/lg/LTR-09

Copy to: Josh Love, MidAmerican

Tables

Table 1

Summary of Closure/Post-Closure Cost Estimates
MidAmerican Energy Company
Inactive CCR Impoundments
March 2024

	Neal North	WSEC	LGS	TOTAL
Total Dollars				
Current Closure Cost	Closed	$25,000	Closed	
Current Post-Closure Cost	$4,484,000	$5,540,000	$3,055,000	
Total Dollar Value Per Facility	$4,484,000	$5,565,000	$3,055,000	
Total				**$13,104,000**

Notes:
Supporting calculations provided on additional sheets.
WSEC - Walter Scott, Jr. Energy Center.
LGS - Louisa Generating Station, closure completed in 2020.
Neal North closure completed in 2022.

Attachments

Attachment A

Cost Estimate Supporting Calculations

Neal North Impoundments
Post-Closure Cost Estimate
March 2024

		Unit	Unit Cost	Quantity	Total
30 YEAR POST CLOSURE					
1	General site facilities, access roads, and fencing maintenance.	Annual	$12,143	29	$352,146
2	Cap and vegetative cover maintenance.	Annual	$14,572	29	$422,575
3	Drainage and erosion control system maintenance.	Annual	$8,622	29	$250,024
4	Groundwater and surface water monitoring systems maintenance.				
	Annual Allowance for Repairs	Annual	$1,384	29	$40,142
	Well Abandonment	Well (one time)	$820	37	$30,347
5	Groundwater/surface water quality gauging and sampling.	Semiannual	$14,000	58	$812,000
6	Groundwater/surface water evaluations and reports.	Annual	$34,000	29	$986,000
7	Facility inspections and reports.	Annual	$5,558	29	$161,170
8	Engineering and technical services.	Annual	$13,842	29	$401,419
9	Legal, financial, and administrative services.	Annual	$13,842	29	$401,419
10	Financial assurance, accounting, audits, and reports.	Annual	$13,842	29	$401,419
11	Corrective Measures				
	Delineation and assessment	Lump	$75,000	1	$75,000
	Additional annual monitoring and reporting	Annual	$30,000	5	$150,000
			Post-Closure Subtotal		**$4,483,662**

Notes:
Start date for financial calculations is March 1, 2024.

Walter Scott, Jr. Energy Center North Impoundment
Closure and Post-Closure Cost Estimate
March 2024

		Unit	Unit Cost	Quantity	Total
CLOSURE					
1	Closure and Post-Closure Plan (C/PC) document revisions.	Lump	$0	0	$0
2	Site preparation, earthwork, and final grading.				
	Grading, General Fill	CY	$0	0	$0
	Coal Combustion Residue (CCR) Grading	CY	$0	0	$0
3	Drainage control culverts, piping, and structures.	Lump	$0	0	$0
4	Erosion control structures, sediment ponds, and terraces.	Lump	$0	0	$0
5	Final cap construction (soil and 40 mil LLDPE)	acres	$0	0	$0
6	Cap vegetation soil placement (included line 5).				
	Mobilization/Appurtenant Work (percent of earthwork)	Percent	0%	0	$0
7	Cap seeding, mulching, and fertilization.	Acre	$0	0	$0
8	Monitoring well and piezometer modifications.	Lump	$0	0	$0
9	Monitoring well installations and abandonments.	Lump	$0	0	$0
10	Facility modifications to effect closed status.	Lump	$0	0	$0
11	Engineering and technical services (percent of earthwork).	Percent	0%	0	$0
12	Legal, financial, and administrative services.	Lump	$0	0	$0
13	Closure compliance certifications and documentation.	Lump	$25,000	1	$25,000
				Closure Subtotal	**$25,000**
30 YEAR POST CLOSURE (FEDERAL CCR RULE)					
1	General site facilities, access roads, and fencing maintenance.	Annual	$12,143	30	$364,289
2	Cap and vegetative cover maintenance.	Annual	$22,732	30	$681,949
3	Drainage and erosion control system maintenance.	Annual	$14,572	30	$437,147
4	Groundwater and surface water monitoring systems maintenance.				
	Annual Allowance for Repairs	Annual	$1,384	30	$41,526
	Well Abandonment	Well (one time)	$820	24	$19,685
5	Groundwater/surface water quality gauging and sampling.	Semiannual	$18,000	60	$1,080,000
6	Groundwater/surface water evaluations and reports.	Annual	$26,000	30	$780,000
7	Facility inspections and reports.	Annual	$11,074	30	$332,209
8	Engineering and technical services.	Annual	$20,763	30	$622,892
9	Legal, financial, and administrative services.	Annual	$13,842	30	$415,261
10	Financial assurance, accounting, audits, and reports.	Annual	$13,842	30	$415,261
11	Corrective Measures				
	Delineation and assessment	Lump	$200,000	1	$200,000
	Additional annual monitoring and reporting	Annual	$30,000	5	$150,000
				Post-Closure Subtotal	**$5,540,219**

Notes:
Start date for financial calculations is March 1, 2024.

Louisa Generating Station Bottom Ash Impoundment
Closure and Post-Closure Cost Estimate
March 2024

		Unit	Unit Cost	Quantity	Total
30 YEAR POST CLOSURE (FEDERAL CCR RULE)					
1	General site facilities, access roads, and fencing maintenance.	Annual	$11,992	27	$323,781
2	Cap and vegetative cover maintenance.	Annual	$10,793	27	$291,403
3	Drainage and erosion control system maintenance.	Annual	$3,598	27	$97,134
4	Groundwater and surface water monitoring systems maintenance.				
	Annual Allowance for Repairs	Annual	$1,367	27	$36,908
	Well Abandonment	Well (one time)	$820	13	$10,662
5	Groundwater/surface water quality gauging and sampling.	Semiannual	$7,500	54	$405,000
6	Groundwater/surface water evaluations and reports.	Annual	$23,000	27	$621,000
7	Facility inspections and reports.	Annual	$5,468	27	$147,634
8	Engineering and technical services.	Annual	$13,842	27	$373,735
9	Legal, financial, and administrative services.	Annual	$13,842	27	$373,735
10	Financial assurance, accounting, audits, and reports.	Annual	$13,842	27	$373,735
11	Corrective Measures				
	Delineation and assessment	Lump	$0	0	$0
	Additional annual monitoring and reporting	Annual	$0	0	$0
			Post-Closure Subtotal		**$3,054,727**

Notes:
Start date for financial calculations is March 1, 2024.

Attachment B

Inflation Factor

The 'Inflation Factor'– 2023 over 2022 for Landfill Financial Assistance Cost Estimates

Ref. Iowa Admin. Code [567] sub-sections (3), (4) & (5) in each of sections 113.14, 115.31, 114.31 & 103.3

Every Annual Financial Assurance Report must UPDATE Closure, Postclosure &/or Corrective Action Cost Estimates, **IN CURRENT DOLLARS**, certified by an Iowa-licensed professional engineer.

IF no other re-assessment/computations are done**, Cost Estimates HAVE TO **AT LEAST** BE adjusted for annual inflation By **multiplying** last year's Cost Estimates **times** the **Inflation Factor**.

As of *January 25, 2024*, the Inflation Factor for this year's Financial Assurance Reports is **1.026**

as Derived from Gross Domestic Product statistics, using the formula:

Implicit Price Deflator of most recent quarter ÷ Implicit Price Deflator of previous year's same corresponding quarter	= **Inflation Factor**

Find the Implicit Price Deflators for GROSS DOMESTIC PRODUCT at this website of the U.S. Dept. of Commerce, Bureau of Economic Analysis (BEA):
https://apps.bea.gov/iTable/?reqid=19&step=3&isuri=1&1921=survey&1903=13

So it is then that:

$$\frac{\text{20}\mathbf{23}\ 4^{th}\text{ quarter implicit price deflator}}{\text{20}\mathbf{22}\ 4^{th}\text{ quarter implicit price deflator}} = \textbf{Inflation Factor}$$

123.226 / **120.093**	= **1.026**

as An ***Example***, ---with No other re-assessment/re-computations** being made...

IF, Last *Year's combined Cost Estimates* = **$2,000,000**

Applying this year's Inflation Factor then *means*:

$2,000,000 X* 1.026 = *$2,052,000

i.e. This Year's updated combined Cost Estimates adjusted for inflation.

Source of the Implicit Price Deflators for **GROSS DOMESTIC PRODUCT**:

U.S. Department of Commerce
Bureau of Economic Analysis (BEA)
4600 Silver Hill Road
Washington, DC 20233
Ph. (301) 278-9004
Link for an e-mail: Submit a Customer Service Request

** ***If*** *Cost Estimates* ***are*** re-assessed *and* re-computed *and yet found to be effectively the same as last year,* ***then*** *a statement to that effect has to be included with the Financial Assurance Report materials.*

◆Updated January 25, 2024◆

Coal Combustion Residue Monofill Financial Assurance Report Form

Section 1: Facility Information *(please print or type)*

Information Requested	
Facility Name	Walter Scott Jr. Energy Center
Permitted Agency/Entity	MidAmerican Energy Company
Permit Number	78-SDP-26-06P

Section 2: Closure/Postclosure or Corrective Action Cost Estimates

Information Requested	Cost Estimate	Date of Cost Estimate
Updated Closure Cost Estimate	$ 19,031,000	March 7, 2024
Updated Postclosure Cost Estimate	$ 5,437,000	March 7, 2024
Initial or Updated Corrective Action Cost Estimate	$	

*Attach closure/postclosure cost estimate(s) signed and certified by an Iowa-licensed professional engineer. Cost estimates shall include, at a minimum, each of the cost line items defined in 103.3(3)"c" for closure and 103.3(4)"c" for postclosure. Please provide closure and/or postclosure site area acreage information with the estimates.

Provide a cost estimate for corrective action only if corrective action is required and a corrective action plan has been approved by the Department. Attach the corrective action cost estimate signed and certified by an Iowa-licensed professional engineer. The cost estimate shall account for total costs of the activities described in the approved corrective action plan for the corrective action period.

Section 3: Facility Waste Tonnage Information

Information Requested	Tons
Remaining permitted capacity as of the beginning of permit holder's current fiscal year	5,774,224
Amount of waste disposed of at the facility during the prior year	230,214

Section 4: Proof of Compliance

Publicly Owned Coal Combustion Residue Monofills *(ATTACH AUDIT REPORT)*
Owner's Most Recent Annual Audit Report Prepared by: _____ For fiscal year ending: _____
Privately Owned Coal Combustion Residue Monofills *(ATTACH AFFIDAVIT)*
Attach owner/operator's affidavit indicating that an annual review has been performed by a certified public accountant to determine whether the privately owned monofill is in compliance with IAC 567 Chapter 103. The affidavit shall state the name of the certified public accountant, the dates and conclusions of the review, and the steps taken to rectify any deficiencies identified by the accountant.

Section 5: Financial Assurance Instrument

Type and Value of Financial Assurance Instrument(s)			(ATTACH INSTRUMENT(S))
Assurance Instrument	**Establishment Date**	**Mechanism Covers**	**Instrument Value**
Trust Fund 567 IAC 103.3(6)"a"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Surety Bond 567 IAC 103.3(6)"b"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Letter of Credit 567 IAC 103.3(6)"c"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Insurance 567 IAC 103.3(6)"d"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Corporate Financial Test 567 IAC 103.3(6)"e"	12/31/13	Closure ☒ Postclosure ☒ Corrective Action ☐	$ 24,468,000
Local Gov't. Financial Test 567 IAC 103.3(6)"f"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Corporate Guarantee 567 IAC 103.3(6)"g"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Local Gov't Guarantee 567 IAC 103.3(6)"h"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Local Gov't. Dedicated Fund 567 IAC 103.3(6)"i"		Closure ☐ Postclosure ☐ Corrective Action ☐	$

Section 7: Fund Payments *(only if using dedicated or trust fund)*

Completion of the following fund information complies with the annual financial statement requirements of IAC 567 103.3(3)"a" and 103.3(4)"a" by indicating the current balance(s) of the dedicated/trust fund and the projected amount(s) to be deposited in the fund(s).

Under "Beginning Balance", please state the fund balance 30 days after the start of the previous fiscal year, for "Ending Balance", indicate the fund balance 30 days after the close of the previous fiscal year, and for "Projected Deposit", indicate the amount to be deposited within 30 days of the close of the permit holder's fiscal year.

Information Requested	Beginning Balance	Ending Balance	Projected Deposit
Dedicated Fund Balance *(see formula below)*	$	$	$
Trust Fund Balance *(see formula below)*	$	$	$

Formula for Projected Deposits

Dedicated/Trust Fund

$$\frac{CE - CB}{Y}$$

Where "CE" is the closure or postclosure cost estimate, "CB" is the balance 30 days after close of the previous fiscal year, and "Y" is number of years remaining in the pay-in period.

If needed, the space below can be used to show calculations for projected deposit(s)

Section 8: Permit Holder Endorsement

SUBMITTAL OF THIS COMPLETED AND ENDORSED FORM ALONG WITH ALL REQUIRED DOCUMENTATION ESTABLISHES NOTIFICATION AND PROOF OF PERMIT HOLDER COMPLIANCE WITH IAC 567 CHAPTER 103.		
Blake Groen	Vice President and Chief Financial Officer	
Name of Official	Title	
MidAmerican Energy Company		
Agency/Entity		
666 Grand Avenue PO Box 657		
Address		
Des Moines	IA	50306-0657
City	State	Zip
515-252-6925		
Telephone	Fax	
Blake.groen@midamerican.com		
Email Address		

	Vice President & CFO	3/28/24
Signature of Official	Title	Date

Questions? Contact Chad A. Stobbe at (515) 242-5851 or Chad.Stobbe@dnr.iowa.gov

Coal Combustion Residue Monofill Financial Assurance Report Form

Section 1: FACILITY INFORMATION *(please print or type)*

Information Requested	
Facility Name	Louisa Generating Station
Permitted Agency/Entity	MidAmerican Energy Company
Permit Number	70-SDP-23-18C

Section 2: CLOSURE/POSTCLOSURE OR CORRECTIVE ACTION COST ESTIMATES

Information Requested	Cost Estimate	Date of Cost Estimate
Updated Closure Cost Estimate	$ 0	March 7, 2024
Updated Postclosure Cost Estimate	$ 3,055,000	March 7, 2024
Initial or Updated Corrective Action Cost Estimate	$	

*Attach closure/postclosure cost estimate(s) signed and certified by an Iowa-licensed professional engineer. Cost estimates shall include, at a minimum, each of the cost line items defined in 103.3(3)"c" for closure and 103.3(4)"c" for postclosure. Please provide closure and/or postclosure site area acreage information with the estimates.

Provide a cost estimate for corrective action only if corrective action is required and a corrective action plan has been approved by the Department. Attach the corrective action cost estimate signed and certified by an Iowa-licensed professional engineer. The cost estimate shall account for total costs of the activities described in the approved corrective action plan for the corrective action period.

Section 3: FACILITY WASTE TONNAGE INFORMATION

Information Requested	Tons
Remaining permitted capacity as of the beginning of permit holder's current fiscal year	
Amount of waste disposed of at the facility during the prior year	

Section 4: PROOF OF COMPLIANCE

Publicly Owned Coal Combustion Residue Monofills *(ATTACH AUDIT REPORT)*

Owner's Most Recent Annual Audit Report

Prepared by: _____

For fiscal year ending: _____

Privately Owned Coal Combustion Residue Monofills *(ATTACH AFFIDAVIT)*

Attach owner/operator's affidavit indicating that an annual review has been performed by a certified public accountant to determine whether the privately owned monofill is in compliance with IAC 567 Chapter 103. The affidavit shall state the name of the certified public accountant, the dates and conclusions of the review, and the steps taken to rectify any deficiencies identified by the accountant.

Section 5: FINANCIAL ASSURANCE INSTRUMENT

Type and Value of Financial Assurance Instrument(s) *(ATTACH INSTRUMENT(S)*

Assurance Instrument	Establishment Date	Mechanism Covers	Instrument Value
Trust Fund 567 IAC 103.3(6)"a"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Surety Bond 567 IAC 103.3(6)"b"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Letter of Credit 567 IAC 103.3(6)"c"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Insurance 567 IAC 103.3(6)"d"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Corporate Financial Test 567 IAC 103.3(6)"e"	12/31/13	Closure ☐ Postclosure ☒ Corrective Action ☐	$ 3,055,000
Local Gov't. Financial Test 567 IAC 103.3(6)"f"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Corporate Guarantee 567 IAC 103.3(6)"g"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Local Gov't Guarantee 567 IAC 103.3(6)"h"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Local Gov't. Dedicated Fund 567 IAC 103.3(6)"i"		Closure ☐ Postclosure ☐ Corrective Action ☐	$

Section 7: FUND PAYMENTS *(only if using dedicated or trust fund)*

Completion of the following fund information complies with the annual financial statement requirements of IAC 567 103.3(3)"a" and 103.3(4)"a" by indicating the current balance(s) of the dedicated/trust fund and the projected amount(s) to be deposited in the fund(s).

Under "Beginning Balance", please state the fund balance 30 days after the start of the previous fiscal year, for "Ending Balance", indicate the fund balance 30 days after the close of the previous fiscal year, and for "Projected Deposit", indicate the amount to be deposited within 30 days of the close of the permit holder's fiscal year.

Information Requested	Beginning Balance	Ending Balance	Projected Deposit
Dedicated Fund Balance *(see formula below)*	$	$	$
Trust Fund Balance *(see formula below)*	$	$	$

Formula for Projected Deposits

Dedicated/Trust Fund

$$\frac{CE - CB}{Y}$$

Where "CE" is the closure or postclosure cost estimate, "CB" is the balance 30 days after close of the previous fiscal year, and "Y" is number of years remaining in the pay-in period.

If needed, the space below can be used to show calculations for projected deposit(s)

Section 8: Permit Holder Endorsement

SUBMITTAL OF THIS COMPLETED AND ENDORSED FORM ALONG WITH ALL REQUIRED DOCUMENTATION ESTABLISHES NOTIFICATION AND PROOF OF PERMIT HOLDER COMPLIANCE WITH IAC 567 CHAPTER 103.		
Blake Groen	Vice President and Chief Financial Officer	
Name of Official	Title	
MidAmerican Energy Company		
Agency/Entity		
666 Grand Avenue PO Box 657		
Address		
Des Moines	IA	50306-0657
City	State	Zip
515-252-6925		
Telephone	Fax	
Blake.groen@midamerican.com		
Email Address		

	Vice President & CFO	3/28/24
Signature of Official	Title	Date

Questions? Contact Chad A. Stobbe at (515) 242-5851 or Chad.Stobbe@dnr.iowa.gov

Coal Combustion Residue Monofill
Financial Assurance Report Form

Section 1: FACILITY INFORMATION *(please print or type)*

Information Requested	
Facility Name	Neal North
Permitted Agency/Entity	MidAmerican Energy Company
Permit Number	97-SDP-22-16C

Section 2: CLOSURE/POSTCLOSURE OR CORRECTIVE ACTION COST ESTIMATES

Information Requested	Cost Estimate	Date of Cost Estimate
Updated Closure Cost Estimate	$ 0	March 7, 2024
Updated Postclosure Cost Estimate	$ 4,484,000	March 7, 2024
Initial or Updated Corrective Action Cost Estimate	$	

*Attach closure/postclosure cost estimate(s) signed and certified by an Iowa-licensed professional engineer. Cost estimates shall include, at a minimum, each of the cost line items defined in 103.3(3)"c" for closure and 103.3(4)"c" for postclosure. Please provide closure and/or postclosure site area acreage information with the estimates.

Provide a cost estimate for corrective action only if corrective action is required and a corrective action plan has been approved by the Department. Attach the corrective action cost estimate signed and certified by an Iowa-licensed professional engineer. The cost estimate shall account for total costs of the activities described in the approved corrective action plan for the corrective action period.

Section 3: FACILITY WASTE TONNAGE INFORMATION

Information Requested	Tons
Remaining permitted capacity as of the beginning of permit holder's current fiscal year	
Amount of waste disposed of at the facility during the prior year	

Section 4: PROOF OF COMPLIANCE

Publicly Owned Coal Combustion Residue Monofills *(ATTACH AUDIT REPORT)*
Owner's Most Recent Annual Audit Report Prepared by: _____ For fiscal year ending: _____
Privately Owned Coal Combustion Residue Monofills *(ATTACH AFFIDAVIT)*
Attach owner/operator's affidavit indicating that an annual review has been performed by a certified public accountant to determine whether the privately owned monofill is in compliance with IAC 567 Chapter 103. The affidavit shall state the name of the certified public accountant, the dates and conclusions of the review, and the steps taken to rectify any deficiencies identified by the accountant.

Section 5: FINANCIAL ASSURANCE INSTRUMENT

Type and Value of Financial Assurance Instrument(s)			(ATTACH INSTRUMENT(S))
Assurance Instrument	**Establishment Date**	**Mechanism Covers**	**Instrument Value**
Trust Fund 567 IAC 103.3(6)"a"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Surety Bond 567 IAC 103.3(6)"b"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Letter of Credit 567 IAC 103.3(6)"c"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Insurance 567 IAC 103.3(6)"d"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Corporate Financial Test 567 IAC 103.3(6)"e"	12/31/13	Closure ☐ Postclosure ☒ Corrective Action ☐	$ 4,484,000
Local Gov't. Financial Test 567 IAC 103.3(6)"f"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Corporate Guarantee 567 IAC 103.3(6)"g"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Local Gov't Guarantee 567 IAC 103.3(6)"h"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Local Gov't. Dedicated Fund 567 IAC 103.3(6)"i"		Closure ☐ Postclosure ☐ Corrective Action ☐	$

Section 7: FUND PAYMENTS *(only if using dedicated or trust fund)*

Completion of the following fund information complies with the annual financial statement requirements of IAC 567 103.3(3)"a" and 103.3(4)"a" by indicating the current balance(s) of the dedicated/trust fund and the projected amount(s) to be deposited in the fund(s).

Under "Beginning Balance", please state the fund balance 30 days after the start of the previous fiscal year, for "Ending Balance", indicate the fund balance 30 days after the close of the previous fiscal year, and for "Projected Deposit", indicate the amount to be deposited within 30 days of the close of the permit holder's fiscal year.

Information Requested	Beginning Balance	Ending Balance	Projected Deposit
Dedicated Fund Balance *(see formula below)*	$	$	$
Trust Fund Balance *(see formula below)*	$	$	$

Formula for Projected Deposits

Dedicated/Trust Fund

$$\frac{CE - CB}{Y}$$

Where "CE" is the closure or postclosure cost estimate, "CB" is the balance 30 days after close of the previous fiscal year, and "Y" is number of years remaining in the pay-in period.

If needed, the space below can be used to show calculations for projected deposit(s)

Section 8: Permit Holder Endorsement

Submittal of this completed and endorsed form along with all required documentation establishes Notification and Proof of Permit Holder Compliance with IAC 567 Chapter 103.		
Blake Groen	Vice President and Chief Financial Officer	
Name of Official	Title	
MidAmerican Energy Company		
Agency/Entity		
666 Grand Avenue PO Box 657		
Address		
Des Moines	IA	50306-0657
City	State	Zip
515-252-6925		
Telephone	Fax	
Blake.groen@midamerican.com		
Email Address		

	Vice President & CFO	3/28/24
Signature of Official	Title	Date

Questions? Contact Chad A. Stobbe at (515) 242-5851 or Chad.Stobbe@dnr.iowa.gov

Coal Combustion Residue Monofill Financial Assurance Report Form

Section 1: FACILITY INFORMATION *(please print or type)*

Information Requested	
Facility Name	Walter Scott Jr. Energy Center
Permitted Agency/Entity	MidAmerican Energy Company
Permit Number	78-SDP-33-16C

Section 2: CLOSURE/POSTCLOSURE OR CORRECTIVE ACTION COST ESTIMATES

Information Requested	Cost Estimate	Date of Cost Estimate
Updated Closure Cost Estimate	$ 25,000	March 7, 2024
Updated Postclosure Cost Estimate	$ 5,540,000	March 7, 2024
Initial or Updated Corrective Action Cost Estimate	$	

*Attach closure/postclosure cost estimate(s) signed and certified by an Iowa-licensed professional engineer. Cost estimates shall include, at a minimum, each of the cost line items defined in 103.3(3)"c" for closure and 103.3(4)"c" for postclosure. Please provide closure and/or postclosure site area acreage information with the estimates.

Provide a cost estimate for corrective action only if corrective action is required and a corrective action plan has been approved by the Department. Attach the corrective action cost estimate signed and certified by an Iowa-licensed professional engineer. The cost estimate shall account for total costs of the activities described in the approved corrective action plan for the corrective action period.

Section 3: FACILITY WASTE TONNAGE INFORMATION

Information Requested	Tons
Remaining permitted capacity as of the beginning of permit holder's current fiscal year	
Amount of waste disposed of at the facility during the prior year	

Section 4: PROOF OF COMPLIANCE

Publicly Owned Coal Combustion Residue Monofills *(ATTACH AUDIT REPORT)*

Owner's Most Recent Annual Audit Report

Prepared by: _____

For fiscal year ending: _____

Privately Owned Coal Combustion Residue Monofills *(ATTACH AFFIDAVIT)*

Attach owner/operator's affidavit indicating that an annual review has been performed by a certified public accountant to determine whether the privately owned monofill is in compliance with IAC 567 Chapter 103. The affidavit shall state the name of the certified public accountant, the dates and conclusions of the review, and the steps taken to rectify any deficiencies identified by the accountant.

Section 5: FINANCIAL ASSURANCE INSTRUMENT

Type and Value of Financial Assurance Instrument(s)			*(ATTACH INSTRUMENT(S)*
Assurance Instrument	**Establishment Date**	**Mechanism Covers**	**Instrument Value**
Trust Fund 567 IAC 103.3(6)"a"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Surety Bond 567 IAC 103.3(6)"b"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Letter of Credit 567 IAC 103.3(6)"c"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Insurance 567 IAC 103.3(6)"d"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Corporate Financial Test 567 IAC 103.3(6)"e"	12/31/13	Closure ☒ Postclosure ☒ Corrective Action ☐	$ 5,565,000
Local Gov't. Financial Test 567 IAC 103.3(6)"f"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Corporate Guarantee 567 IAC 103.3(6)"g"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Local Gov't Guarantee 567 IAC 103.3(6)"h"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Local Gov't. Dedicated Fund 567 IAC 103.3(6)"i"		Closure ☐ Postclosure ☐ Corrective Action ☐	$

Section 7: FUND PAYMENTS *(only if using dedicated or trust fund)*

Completion of the following fund information complies with the annual financial statement requirements of IAC 567 103.3(3)"a" and 103.3(4)"a" by indicating the current balance(s) of the dedicated/trust fund and the projected amount(s) to be deposited in the fund(s).

Under "Beginning Balance", please state the fund balance 30 days after the start of the previous fiscal year, for "Ending Balance", indicate the fund balance 30 days after the close of the previous fiscal year, and for "Projected Deposit", indicate the amount to be deposited within 30 days of the close of the permit holder's fiscal year.

Information Requested	Beginning Balance	Ending Balance	Projected Deposit
Dedicated Fund Balance *(see formula below)*	$	$	$
Trust Fund Balance *(see formula below)*	$	$	$

Formula for Projected Deposits

Dedicated/Trust Fund

$$\frac{CE - CB}{Y}$$

Where "CE" is the closure or postclosure cost estimate, "CB" is the balance 30 days after close of the previous fiscal year, and "Y" is number of years remaining in the pay-in period.

If needed, the space below can be used to show calculations for projected deposit(s)

Section 8: Permit Holder Endorsement

SUBMITTAL OF THIS COMPLETED AND ENDORSED FORM ALONG WITH ALL REQUIRED DOCUMENTATION ESTABLISHES NOTIFICATION AND PROOF OF PERMIT HOLDER COMPLIANCE WITH IAC 567 CHAPTER 103.

Blake Groen	Vice President and Chief Financial Officer	
Name of Official	Title	
MidAmerican Energy Company		
Agency/Entity		
666 Grand Avenue PO Box 657		
Address		
Des Moines	IA	50306-0657
City	State	Zip
515-252-6925		
Telephone	Fax	
Blake.groen@midamerican.com		
Email Address		

	Vice President & CFO	3/28/24
Signature of Official	Title	Date

Questions? Contact Chad A. Stobbe at (515) 242-5851 or Chad.Stobbe@dnr.iowa.gov

Coal Combustion Residue Monofill
Financial Assurance Report Form

Section 1: Facility Information *(please print or type)*

Information Requested	
Facility Name	Louisa Generating Station - East
Permitted Agency/Entity	MidAmerican Energy Company
Permit Number	70-SDP-16-04P

Section 2: Closure/Postclosure or Corrective Action Cost Estimates

Information Requested	Cost Estimate	Date of Cost Estimate
Updated Closure Cost Estimate	$ 2,760,000	March 7, 2024
Updated Postclosure Cost Estimate	$ 1,266,000	March 7, 2024
Initial or Updated Corrective Action Cost Estimate	$	

*Attach closure/postclosure cost estimate(s) signed and certified by an Iowa-licensed professional engineer. Cost estimates shall include, at a minimum, each of the cost line items defined in 103.3(3)"c" for closure and 103.3(4)"c" for postclosure. Please provide closure and/or postclosure site area acreage information with the estimates.

Provide a cost estimate for corrective action only if corrective action is required and a corrective action plan has been approved by the Department. Attach the corrective action cost estimate signed and certified by an Iowa-licensed professional engineer. The cost estimate shall account for total costs of the activities described in the approved corrective action plan for the corrective action period.

Section 3: Facility Waste Tonnage Information

Information Requested	Tons
Remaining permitted capacity as of the beginning of permit holder's current fiscal year	108,562
Amount of waste disposed of at the facility during the prior year	61,808

Section 4: Proof of Compliance

Publicly Owned Coal Combustion Residue Monofills *(ATTACH AUDIT REPORT)*

Owner's Most Recent Annual Audit Report

Prepared by: _____

For fiscal year ending: _____

Privately Owned Coal Combustion Residue Monofills *(ATTACH AFFIDAVIT)*

Attach owner/operator's affidavit indicating that an annual review has been performed by a certified public accountant to determine whether the privately owned monofill is in compliance with IAC 567 Chapter 103. The affidavit shall state the name of the certified public accountant, the dates and conclusions of the review, and the steps taken to rectify any deficiencies identified by the accountant.

Section 5: FINANCIAL ASSURANCE INSTRUMENT

Type and Value of Financial Assurance Instrument(s)			*(ATTACH INSTRUMENT(S))*
Assurance Instrument	**Establishment Date**	**Mechanism Covers**	**Instrument Value**
Trust Fund 567 IAC 103.3(6)"a"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Surety Bond 567 IAC 103.3(6)"b"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Letter of Credit 567 IAC 103.3(6)"c"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Insurance 567 IAC 103.3(6)"d"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Corporate Financial Test 567 IAC 103.3(6)"e"	12/31/13	Closure ☒ Postclosure ☒ Corrective Action ☐	$ 4,026,000
Local Gov't. Financial Test 567 IAC 103.3(6)"f"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Corporate Guarantee 567 IAC 103.3(6)"g"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Local Gov't Guarantee 567 IAC 103.3(6)"h"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Local Gov't. Dedicated Fund 567 IAC 103.3(6)"i"		Closure ☐ Postclosure ☐ Corrective Action ☐	$

Section 7: FUND PAYMENTS *(only if using dedicated or trust fund)*

Completion of the following fund information complies with the annual financial statement requirements of IAC 567 103.3(3)"a" and 103.3(4)"a" by indicating the current balance(s) of the dedicated/trust fund and the projected amount(s) to be deposited in the fund(s).

Under "Beginning Balance", please state the fund balance 30 days after the start of the previous fiscal year, for "Ending Balance", indicate the fund balance 30 days after the close of the previous fiscal year, and for "Projected Deposit", indicate the amount to be deposited within 30 days of the close of the permit holder's fiscal year.

Information Requested	Beginning Balance	Ending Balance	Projected Deposit
Dedicated Fund Balance *(see formula below)*	$	$	$
Trust Fund Balance *(see formula below)*	$	$	$

Formula for Projected Deposits

Dedicated/Trust Fund

$$\frac{CE - CB}{Y}$$

Where "CE" is the closure or postclosure cost estimate, "CB" is the balance 30 days after close of the previous fiscal year, and "Y" is number of years remaining in the pay-in period.

If needed, the space below can be used to show calculations for projected deposit(s)

Section 8: Permit Holder Endorsement

SUBMITTAL OF THIS COMPLETED AND ENDORSED FORM ALONG WITH ALL REQUIRED DOCUMENTATION ESTABLISHES NOTIFICATION AND PROOF OF PERMIT HOLDER COMPLIANCE WITH IAC 567 CHAPTER 103.

Blake Groen	Vice President and Chief Financial Officer	
Name of Official	Title	
MidAmerican Energy Company		
Agency/Entity		
666 Grand Avenue PO Box 657		
Address		
Des Moines	IA	50306-0657
City	State	Zip
515-252-6925		
Telephone	Fax	
Blake.groen@midamerican.com		
Email Address		

	Vice President & CFO	3/28/24
Signature of Official	Title	Date

Questions? Contact Chad A. Stobbe at (515) 242-5851 or Chad.Stobbe@dnr.iowa.gov

Coal Combustion Residue Monofill Financial Assurance Report Form

Section 1: FACILITY INFORMATION *(please print or type)*

Information Requested	
Facility Name	Louisa Generating Station - West
Permitted Agency/Entity	MidAmerican Energy Company
Permit Number	70-SDP-17-04C

Section 2: CLOSURE/POSTCLOSURE OR CORRECTIVE ACTION COST ESTIMATES

Information Requested	Cost Estimate	Date of Cost Estimate
Updated Closure Cost Estimate	$ 0	March 7, 2024
Updated Postclosure Cost Estimate	$ 767,000	March 7, 2024
Initial or Updated Corrective Action Cost Estimate	$	

*Attach closure/postclosure cost estimate(s) signed and certified by an Iowa-licensed professional engineer. Cost estimates shall include, at a minimum, each of the cost line items defined in 103.3(3)"c" for closure and 103.3(4)"c" for postclosure. Please provide closure and/or postclosure site area acreage information with the estimates.

Provide a cost estimate for corrective action only if corrective action is required and a corrective action plan has been approved by the Department. Attach the corrective action cost estimate signed and certified by an Iowa-licensed professional engineer. The cost estimate shall account for total costs of the activities described in the approved corrective action plan for the corrective action period.

Section 3: FACILITY WASTE TONNAGE INFORMATION

Information Requested	Tons
Remaining permitted capacity as of the beginning of permit holder's current fiscal year	
Amount of waste disposed of at the facility during the prior year	

Section 4: PROOF OF COMPLIANCE

Publicly Owned Coal Combustion Residue Monofills *(ATTACH AUDIT REPORT)*

Owner's Most Recent Annual Audit Report

Prepared by: _____

For fiscal year ending: _____

Privately Owned Coal Combustion Residue Monofills *(ATTACH AFFIDAVIT)*

Attach owner/operator's affidavit indicating that an annual review has been performed by a certified public accountant to determine whether the privately owned monofill is in compliance with IAC 567 Chapter 103. The affidavit shall state the name of the certified public accountant, the dates and conclusions of the review, and the steps taken to rectify any deficiencies identified by the accountant.

Section 5: FINANCIAL ASSURANCE INSTRUMENT

Type and Value of Financial Assurance Instrument(s)			*(ATTACH INSTRUMENT(S))*
Assurance Instrument	**Establishment Date**	**Mechanism Covers**	**Instrument Value**
Trust Fund 567 IAC 103.3(6)"a"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Surety Bond 567 IAC 103.3(6)"b"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Letter of Credit 567 IAC 103.3(6)"c"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Insurance 567 IAC 103.3(6)"d"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Corporate Financial Test 567 IAC 103.3(6)"e"	12/31/13	Closure ☐ Postclosure ☒ Corrective Action ☐	$ 767,000
Local Gov't. Financial Test 567 IAC 103.3(6)"f"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Corporate Guarantee 567 IAC 103.3(6)"g"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Local Gov't Guarantee 567 IAC 103.3(6)"h"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Local Gov't. Dedicated Fund 567 IAC 103.3(6)"i"		Closure ☐ Postclosure ☐ Corrective Action ☐	$

Section 7: FUND PAYMENTS *(only if using dedicated or trust fund)*

Completion of the following fund information complies with the annual financial statement requirements of IAC 567 103.3(3)"a" and 103.3(4)"a" by indicating the current balance(s) of the dedicated/trust fund and the projected amount(s) to be deposited in the fund(s).

Under "Beginning Balance", please state the fund balance 30 days after the start of the previous fiscal year, for "Ending Balance", indicate the fund balance 30 days after the close of the previous fiscal year, and for "Projected Deposit", indicate the amount to be deposited within 30 days of the close of the permit holder's fiscal year.

Information Requested	Beginning Balance	Ending Balance	Projected Deposit
Dedicated Fund Balance *(see formula below)*	$	$	$
Trust Fund Balance *(see formula below)*	$	$	$

Formula for Projected Deposits

Dedicated/Trust Fund

$$\frac{CE - CB}{Y}$$

Where "CE" is the closure or postclosure cost estimate, "CB" is the balance 30 days after close of the previous fiscal year, and "Y" is number of years remaining in the pay-in period.

If needed, the space below can be used to show calculations for projected deposit(s)

Section 8: Permit Holder Endorsement

SUBMITTAL OF THIS COMPLETED AND ENDORSED FORM ALONG WITH ALL REQUIRED DOCUMENTATION ESTABLISHES NOTIFICATION AND PROOF OF PERMIT HOLDER COMPLIANCE WITH IAC 567 CHAPTER 103.		
Blake Groen	Vice President and Chief Financial Officer	
Name of Official	Title	
MidAmerican Energy Company		
Agency/Entity		
666 Grand Avenue PO Box 657		
Address		
Des Moines	IA	50306-0657
City	State	Zip
515-252-6925		
Telephone	Fax	
Blake.groen@midamerican.com		
Email Address		

	Vice President & CFO	3/28/24
Signature of Official	Title	Date

Questions? Contact Chad A. Stobbe at (515) 242-5851 or Chad.Stobbe@dnr.iowa.gov

Coal Combustion Residue Monofill
Financial Assurance Report Form

Section 1: FACILITY INFORMATION *(please print or type)*

Information Requested	
Facility Name	Neal North (Active)
Permitted Agency/Entity	MidAmerican Energy Company
Permit Number	97-SDP-12-95P

Section 2: CLOSURE/POSTCLOSURE OR CORRECTIVE ACTION COST ESTIMATES

Information Requested	Cost Estimate	Date of Cost Estimate
Updated Closure Cost Estimate	$ 3,364,000	March 7, 2024
Updated Postclosure Cost Estimate	$ 1,476,000	March 7, 2024
Initial or Updated Corrective Action Cost Estimate	$	

*Attach closure/postclosure cost estimate(s) signed and certified by an Iowa-licensed professional engineer. Cost estimates shall include, at a minimum, each of the cost line items defined in 103.3(3)"c" for closure and 103.3(4)"c" for postclosure. Please provide closure and/or postclosure site area acreage information with the estimates.

Provide a cost estimate for corrective action only if corrective action is required and a corrective action plan has been approved by the Department. Attach the corrective action cost estimate signed and certified by an Iowa-licensed professional engineer. The cost estimate shall account for total costs of the activities described in the approved corrective action plan for the corrective action period.

Section 3: FACILITY WASTE TONNAGE INFORMATION

Information Requested	Tons
Remaining permitted capacity as of the beginning of permit holder's current fiscal year	1,250,765
Amount of waste disposed of at the facility during the prior year	38,092

Section 4: PROOF OF COMPLIANCE

Publicly Owned Coal Combustion Residue Monofills *(ATTACH AUDIT REPORT)*
Owner's Most Recent Annual Audit Report Prepared by: _____ For fiscal year ending: _____
Privately Owned Coal Combustion Residue Monofills *(ATTACH AFFIDAVIT)*
Attach owner/operator's affidavit indicating that an annual review has been performed by a certified public accountant to determine whether the privately owned monofill is in compliance with IAC 567 Chapter 103. The affidavit shall state the name of the certified public accountant, the dates and conclusions of the review, and the steps taken to rectify any deficiencies identified by the accountant.

Section 5: FINANCIAL ASSURANCE INSTRUMENT

Type and Value of Financial Assurance Instrument(s) *(ATTACH INSTRUMENT(S)*

Assurance Instrument	Establishment Date	Mechanism Covers	Instrument Value
Trust Fund 567 IAC 103.3(6)"a"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Surety Bond 567 IAC 103.3(6)"b"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Letter of Credit 567 IAC 103.3(6)"c"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Insurance 567 IAC 103.3(6)"d"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Corporate Financial Test 567 IAC 103.3(6)"e"	12/31/13	Closure ☒ Postclosure ☒ Corrective Action ☐	$ 4,840,000
Local Gov't. Financial Test 567 IAC 103.3(6)"f"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Corporate Guarantee 567 IAC 103.3(6)"g"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Local Gov't Guarantee 567 IAC 103.3(6)"h"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Local Gov't. Dedicated Fund 567 IAC 103.3(6)"i"		Closure ☐ Postclosure ☐ Corrective Action ☐	$

Section 7: FUND PAYMENTS *(only if using dedicated or trust fund)*

Completion of the following fund information complies with the annual financial statement requirements of IAC 567 103.3(3)"a" and 103.3(4)"a" by indicating the current balance(s) of the dedicated/trust fund and the projected amount(s) to be deposited in the fund(s).

Under "Beginning Balance", please state the fund balance 30 days after the start of the previous fiscal year, for "Ending Balance", indicate the fund balance 30 days after the close of the previous fiscal year, and for "Projected Deposit", indicate the amount to be deposited within 30 days of the close of the permit holder's fiscal year.

Information Requested	Beginning Balance	Ending Balance	Projected Deposit
Dedicated Fund Balance *(see formula below)*	$	$	$
Trust Fund Balance *(see formula below)*	$	$	$

Formula for Projected Deposits

Dedicated/Trust Fund

$$\frac{CE - CB}{Y}$$

Where "CE" is the closure or postclosure cost estimate, "CB" is the balance 30 days after close of the previous fiscal year, and "Y" is number of years remaining in the pay-in period.

If needed, the space below can be used to show calculations for projected deposit(s)

Section 8: Permit Holder Endorsement

Submittal of this completed and endorsed form along with all required documentation establishes Notification and Proof of Permit Holder Compliance with IAC 567 Chapter 103.		
Blake Groen	Vice President and Chief Financial Officer	
Name of Official	**Title**	
MidAmerican Energy Company		
Agency/Entity		
666 Grand Avenue PO Box 657		
Address		
Des Moines	IA	50306-0657
City	**State**	**Zip**
515-252-6925		
Telephone	**Fax**	
Blake.groen@midamerican.com		
Email Address		

	Vice President & CFO	3/28/24
Signature of Official	**Title**	**Date**

Questions? Contact Chad A. Stobbe at (515) 242-5851 or Chad.Stobbe@dnr.iowa.gov

Coal Combustion Residue Monofill
Financial Assurance Report Form

Section 1: Facility Information *(please print or type)*

Information Requested	
Facility Name	Neal North (Closed)
Permitted Agency/Entity	MidAmerican Energy Company
Permit Number	97-SDP-24-20C

Section 2: Closure/Postclosure or Corrective Action Cost Estimates

Information Requested	Cost Estimate	Date of Cost Estimate
Updated Closure Cost Estimate	$ 0	March 7, 2024
Updated Postclosure Cost Estimate	$ 494,000	March 7, 2024
Initial or Updated Corrective Action Cost Estimate	$	

*Attach closure/postclosure cost estimate(s) signed and certified by an Iowa-licensed professional engineer. Cost estimates shall include, at a minimum, each of the cost line items defined in 103.3(3)"c" for closure and 103.3(4)"c" for postclosure. Please provide closure and/or postclosure site area acreage information with the estimates.

Provide a cost estimate for corrective action only if corrective action is required and a corrective action plan has been approved by the Department. Attach the corrective action cost estimate signed and certified by an Iowa-licensed professional engineer. The cost estimate shall account for total costs of the activities described in the approved corrective action plan for the corrective action period.

Section 3: Facility Waste Tonnage Information

Information Requested	Tons
Remaining permitted capacity as of the beginning of permit holder's current fiscal year	
Amount of waste disposed of at the facility during the prior year	

Section 4: Proof of Compliance

Publicly Owned Coal Combustion Residue Monofills *(ATTACH AUDIT REPORT)*

Owner's Most Recent Annual Audit Report

Prepared by: _____

For fiscal year ending: _____

Privately Owned Coal Combustion Residue Monofills *(ATTACH AFFIDAVIT)*

Attach owner/operator's affidavit indicating that an annual review has been performed by a certified public accountant to determine whether the privately owned monofill is in compliance with IAC 567 Chapter 103. The affidavit shall state the name of the certified public accountant, the dates and conclusions of the review, and the steps taken to rectify any deficiencies identified by the accountant.

Section 5: Financial Assurance Instrument

Type and Value of Financial Assurance Instrument(s) *(ATTACH INSTRUMENT(S))*			
Assurance Instrument	**Establishment Date**	**Mechanism Covers**	**Instrument Value**
Trust Fund 567 IAC 103.3(6)"a"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Surety Bond 567 IAC 103.3(6)"b"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Letter of Credit 567 IAC 103.3(6)"c"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Insurance 567 IAC 103.3(6)"d"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Corporate Financial Test 567 IAC 103.3(6)"e"	12/31/13	Closure ☐ Postclosure ☒ Corrective Action ☐	$ 494,000
Local Gov't. Financial Test 567 IAC 103.3(6)"f"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Corporate Guarantee 567 IAC 103.3(6)"g"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Local Gov't Guarantee 567 IAC 103.3(6)"h"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Local Gov't. Dedicated Fund 567 IAC 103.3(6)"i"		Closure ☐ Postclosure ☐ Corrective Action ☐	$

Section 7: Fund Payments *(only if using dedicated or trust fund)*

Completion of the following fund information complies with the annual financial statement requirements of IAC 567 103.3(3)"a" and 103.3(4)"a" by indicating the current balance(s) of the dedicated/trust fund and the projected amount(s) to be deposited in the fund(s).

Under "Beginning Balance", please state the fund balance 30 days after the start of the previous fiscal year, for "Ending Balance", indicate the fund balance 30 days after the close of the previous fiscal year, and for "Projected Deposit", indicate the amount to be deposited within 30 days of the close of the permit holder's fiscal year.

Information Requested	Beginning Balance	Ending Balance	Projected Deposit
Dedicated Fund Balance *(see formula below)*	$	$	$
Trust Fund Balance *(see formula below)*	$	$	$

Formula for Projected Deposits

Dedicated/Trust Fund

$$\frac{CE - CB}{Y}$$

Where "CE" is the closure or postclosure cost estimate, "CB" is the balance 30 days after close of the previous fiscal year, and "Y" is number of years remaining in the pay-in period.

If needed, the space below can be used to show calculations for projected deposit(s)

Section 8: Permit Holder Endorsement

SUBMITTAL OF THIS COMPLETED AND ENDORSED FORM ALONG WITH ALL REQUIRED DOCUMENTATION ESTABLISHES NOTIFICATION AND PROOF OF PERMIT HOLDER COMPLIANCE WITH IAC 567 CHAPTER 103.

Blake Groen	Vice President and Chief Financial Officer	
Name of Official	**Title**	
MidAmerican Energy Company		
Agency/Entity		
666 Grand Avenue PO Box 657		
Address		
Des Moines	IA	50306-0657
City	**State**	**Zip**
515-252-6925		
Telephone	**Fax**	
Blake.groen@midamerican.com		
Email Address		

[signature]	Vice President & CFO	3/28/24
Signature of Official	**Title**	**Date**

Questions? Contact Chad A. Stobbe at (515) 242-5851 or Chad.Stobbe@dnr.iowa.gov

Coal Combustion Residue Monofill
Financial Assurance Report Form

Section 1: Facility Information *(please print or type)*

Information Requested	
Facility Name	Neal South
Permitted Agency/Entity	MidAmerican Energy Company
Permit Number	97-SDP-13-98P

Section 2: Closure/Postclosure or Corrective Action Cost Estimates

Information Requested	Cost Estimate	Date of Cost Estimate
Updated Closure Cost Estimate	$ 0	March 7, 2024
Updated Postclosure Cost Estimate	$ 776,000	March 7, 2024
Initial or Updated Corrective Action Cost Estimate	$	

*Attach closure/postclosure cost estimate(s) signed and certified by an Iowa-licensed professional engineer. Cost estimates shall include, at a minimum, each of the cost line items defined in 103.3(3)"c" for closure and 103.3(4)"c" for postclosure. Please provide closure and/or postclosure site area acreage information with the estimates.

Provide a cost estimate for corrective action only if corrective action is required and a corrective action plan has been approved by the Department. Attach the corrective action cost estimate signed and certified by an Iowa-licensed professional engineer. The cost estimate shall account for total costs of the activities described in the approved corrective action plan for the corrective action period.

Section 3: Facility Waste Tonnage Information

Information Requested	Tons
Remaining permitted capacity as of the beginning of permit holder's current fiscal year	
Amount of waste disposed of at the facility during the prior year	

Section 4: Proof of Compliance

Publicly Owned Coal Combustion Residue Monofills *(ATTACH AUDIT REPORT)*

Owner's Most Recent Annual Audit Report

Prepared by: _____

For fiscal year ending: _____

Privately Owned Coal Combustion Residue Monofills *(ATTACH AFFIDAVIT)*

Attach owner/operator's affidavit indicating that an annual review has been performed by a certified public accountant to determine whether the privately owned monofill is in compliance with IAC 567 Chapter 103. The affidavit shall state the name of the certified public accountant, the dates and conclusions of the review, and the steps taken to rectify any deficiencies identified by the accountant.

Section 5: FINANCIAL ASSURANCE INSTRUMENT

Type and Value of Financial Assurance Instrument(s)			(ATTACH INSTRUMENT(S))
Assurance Instrument	**Establishment Date**	**Mechanism Covers**	**Instrument Value**
Trust Fund 567 IAC 103.3(6)"a"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Surety Bond 567 IAC 103.3(6)"b"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Letter of Credit 567 IAC 103.3(6)"c"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Insurance 567 IAC 103.3(6)"d"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Corporate Financial Test 567 IAC 103.3(6)"e"	12/31/13	Closure ☐ Postclosure ☒ Corrective Action ☐	$ 776,000
Local Gov't. Financial Test 567 IAC 103.3(6)"f"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Corporate Guarantee 567 IAC 103.3(6)"g"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Local Gov't Guarantee 567 IAC 103.3(6)"h"		Closure ☐ Postclosure ☐ Corrective Action ☐	$
Local Gov't. Dedicated Fund 567 IAC 103.3(6)"i"		Closure ☐ Postclosure ☐ Corrective Action ☐	$

Section 7: FUND PAYMENTS *(only if using dedicated or trust fund)*

Completion of the following fund information complies with the annual financial statement requirements of IAC 567 103.3(3)"a" and 103.3(4)"a" by indicating the current balance(s) of the dedicated/trust fund and the projected amount(s) to be deposited in the fund(s).

Under "Beginning Balance", please state the fund balance 30 days after the start of the previous fiscal year, for "Ending Balance", indicate the fund balance 30 days after the close of the previous fiscal year, and for "Projected Deposit", indicate the amount to be deposited within 30 days of the close of the permit holder's fiscal year.

Information Requested	Beginning Balance	Ending Balance	Projected Deposit
Dedicated Fund Balance *(see formula below)*	$	$	$
Trust Fund Balance *(see formula below)*	$	$	$

Formula for Projected Deposits

Dedicated/Trust Fund

$$\frac{CE - CB}{Y}$$

Where "CE" is the closure or postclosure cost estimate, "CB" is the balance 30 days after close of the previous fiscal year, and "Y" is number of years remaining in the pay-in period.

If needed, the space below can be used to show calculations for projected deposit(s)

Section 8: Permit Holder Endorsement

SUBMITTAL OF THIS COMPLETED AND ENDORSED FORM ALONG WITH ALL REQUIRED DOCUMENTATION ESTABLISHES NOTIFICATION AND PROOF OF PERMIT HOLDER COMPLIANCE WITH IAC 567 CHAPTER 103.		
Blake Groen	Vice President and Chief Financial Officer	
Name of Official	Title	
MidAmerican Energy Company		
Agency/Entity		
666 Grand Avenue PO Box 657		
Address		
Des Moines	IA	50306-0657
City	State	Zip
515-252-6925		
Telephone	Fax	
Blake.groen@midamerican.com		
Email Address		

	Vice President & CFO	3/28/24
Signature of Official	Title	Date

Questions? Contact Chad A. Stobbe at (515) 242-5851 or Chad.Stobbe@dnr.iowa.gov

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, 2023

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)** **666 Grand Avenue** **Des Moines, Iowa 50309-2580** **515-242-4300**	**94-2213782**
001-05152	**PACIFICORP** **(An Oregon Corporation)** **825 N.E. Multnomah Street, Suite 1900** **Portland, Oregon 97232** **888-221-7070**	**93-0246090**
333-90553	**MIDAMERICAN FUNDING, LLC** **(An Iowa Limited Liability Company)** **666 Grand Avenue** **Des Moines, Iowa 50309-2580** **515-242-4300**	**47-0819200**
333-15387	**MIDAMERICAN ENERGY COMPANY** **(An Iowa Corporation)** **666 Grand Avenue** **Des Moines, Iowa 50309-2580** **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	Former Address
EASTERN ENERGY GAS HOLDINGS, LLC	6603 West Broad Street
EASTERN GAS TRANSMISSION AND STORAGE, INC.	Richmond, Virginia 23230

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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

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 privately held by a limited group of investors. As of January 31, 2024, 75,627,913 shares of common stock, no par value, were outstanding.

All shares of outstanding common stock of PacifiCorp are indirectly owned by Berkshire Hathaway Energy Company. As of January 31, 2024, 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, 2024.

All shares of outstanding common stock of MidAmerican Energy Company are owned by its parent company, MHC Inc., which is a direct, wholly owned subsidiary of MidAmerican Funding, LLC. As of January 31, 2024, 70,980,203 shares of common stock, no par value, were outstanding.

All shares of outstanding common stock of Nevada Power Company are owned by its parent company, NV Energy, Inc., which is an indirect, wholly owned subsidiary of Berkshire Hathaway Energy Company. As of January 31, 2024, 1,000 shares of common stock, $1.00 stated value, were outstanding.

All shares of outstanding common stock of Sierra Pacific Power Company are owned by its parent company, NV Energy, Inc. As of January 31, 2024, 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, 2024.

All shares of outstanding common stock of Eastern Gas Transmission and Storage, Inc. are owned 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, 2024, 60,101 shares of common stock, $10,000 par value, were outstanding.

Berkshire Hathaway Energy Company, 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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PART IV

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
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
COVID-19	Coronavirus Disease 2019
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
IUB	Iowa Utilities Board
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
OCA	Iowa Office of Consumer Advocate
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
PTAM	Post Test-year Adjustment Mechanism
PTC	Production Tax Credit
PUCN	Public Utilities Commission of Nevada
RCRA	Resource Conservation and Recovery Act
RAC	Renewable Adjustment Clause
REC	Renewable Energy Credit
RFP	Request for Proposals
RPS	Renewable Portfolio Standards
RRA	Renewable Energy Credit and Sulfur Dioxide Revenue Adjustment Mechanism
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
VIE	Variable Interest Entity
WECC	Western Electricity Coordinating Council
WMP AAC	Wildfire Mitigation Plan Automatic Adjustment Clause
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 2020 Wildfires and the 2022 McKinney Fire (referred to together as "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 and regulations that could affect brokerage, mortgage and franchising transactions;
- 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, receipt of required permits and authorizations, 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 is a holding company that owns a highly diversified portfolio of locally managed and operated businesses principally engaged in the energy industry and is a consolidated subsidiary of Berkshire Hathaway that, as of January 31, 2024, owned 92% of BHE's voting common stock. The balance of BHE's voting common stock is privately held by a limited group of investors.

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, owns 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 owns a highly diversified portfolio of primarily regulated businesses that 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 2023 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, 2023, the Company owns approximately 36,000 MWs of generation capacity in operation and under construction:
    - Approximately 30,100 MWs of generation capacity is owned by its regulated electric utility businesses;
    - Approximately 5,900 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, 32% natural gas, 21% coal, 4% hydroelectric and geothermal and 1% nuclear and other; and,
    - Cumulative investments in (i) owned wind, solar and geothermal generation facilities of $34.1 billion and (ii) wind projects sponsored by third parties, commonly referred to as tax equity investments, of $5.8 billion.
- The Company owns approximately 36,400 miles of electric transmission lines, a 50% interest in ETT that has approximately 2,000 miles of electric transmission lines, approximately 176,800 miles of electric distribution lines and approximately 2,800 substations.
- The BHE Pipeline Group operates approximately 21,000 miles of pipeline with a design capacity of approximately 21.1 Bcf of natural gas per day, transported approximately 15% of the total natural gas consumed in the U.S. during 2023 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 $136.1 billion of home sales in 2023 and has brokerage, mortgage and franchise services in all 50 states. HomeServices' franchise business has approximately 300 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, 2023, the Company had approximately 23,700 employees, consisting of approximately 14,300 (60%) electric and natural gas operations employees, approximately 5,800 (24%) real estate services employees and approximately 3,600 (15%) corporate services employees. HomeServices has approximately 41,000 real estate agents who are independent contractors. As of December 31, 2023, approximately 8,900 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 best-in-class 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, 2023 are included below:

Recordable Incident Rate:	
PacifiCorp	0.48
MidAmerican Energy	0.90
Nevada Power	0.55
Sierra Pacific	0.57
Eastern Energy Gas	0.32
EGTS	0.39
BHE Overall	0.41

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 666 Grand Avenue, Des Moines, Iowa 50309-2580, its telephone number is (515) 242-4300 and its internet address is www.brkenergy.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 the franchise agreements is approximately 22 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, Suite 1900 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.

All shares of PacifiCorp's common stock are indirectly owned by BHE. PacifiCorp also has shares of preferred stock outstanding that are subject to voting rights in certain limited circumstances.

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:

	2023		2022		2021	
Utah	26,062	46 %	26,110	46 %	25,657	46 %
Oregon	13,949	25	13,701	24	13,510	24
Wyoming	8,579	15	8,666	15	8,557	15
Washington	3,850	7	4,181	7	4,199	8
Idaho	3,496	6	3,707	7	3,553	6
California	760	1	799	1	798	1
Total	56,696	100 %	57,164	100 %	56,274	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:

	2023		2022		2021	
GWhs sold:						
Residential	18,159	31 %	18,425	30 %	17,905	29 %
Commercial	20,491	34	19,570	32	18,839	31
Industrial	16,705	28	17,622	28	17,909	29
Other	1,341	2	1,547	2	1,621	3
Total retail	56,696	95	57,164	92	56,274	92
Wholesale	2,911	5	4,836	8	5,113	8
Total GWhs sold	59,607	100 %	62,000	100 %	61,387	100 %
Average number of retail customers (in thousands):						
Residential	1,806	87 %	1,775	87 %	1,745	87 %
Commercial	227	11	225	11	222	11
Industrial	9	1	9	1	9	1
Other	27	1	28	1	27	1
Total	2,069	100 %	2,037	100 %	2,003	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. Peak demand in the winter occurs due to heating requirements. During 2023, PacifiCorp's peak demand was 10,802 MWs in the summer and 8,998 MWs in the winter.

Generating Facilities and Fuel Supply

PacifiCorp has ownership interest in a diverse portfolio of generating facilities. The following table presents certain information regarding PacifiCorp's owned generating facilities as of December 31, 2023:

Generating Facility	Location	Energy Source	Installed / Repowered(1)	Facility Net Capacity (MWs)(2)	Net Owned Capacity (MWs)(2)
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(3)	Rock Springs, WY	Coal	1976-1979	1,049	700
Naughton Nos. 1 and 2	Kemmerer, WY	Coal	1963-1968	357	357
Wyodak No. 1	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:					
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
Chehalis	Chehalis, WA	Natural gas/steam	2003	477	477
Naughton No. 3(4)	Kemmerer, WY	Natural gas	1971	247	247
Gadsby Steam	Salt Lake City, UT	Natural gas	1951-1955	238	238
Hermiston	Hermiston, OR	Natural gas/steam	1996	461	231

Generating Facility	Location	Energy Source	Installed / Repowered[1]	Facility Net Capacity (MWs)[2]	Net Owned Capacity (MWs)[2]
Gadsby Peakers	Salt Lake City, UT	Natural gas	2002	119	119
				3,243	3,013
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
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
				2,296	2,296
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				14,055	10,833
PROJECTS UNDER CONSTRUCTION:					
Various projects				642	642
				14,697	11,475

(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) 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.

(3) During 2023, Jim Bridger Units 1 and 2 operated under a consent decree as described in "Environmental Laws and Regulations" in Item 1 of this Form 10-K. PacifiCorp removed Jim Bridger Units 1 and 2 from coal-fueled service in December 2023 and will convert them to natural gas-fueled generation facilities in 2024.

(4) Naughton No. 3 was converted from a coal-fueled to a natural gas-fueled generating facility in 2020.

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

	2023	2022	2021
Coal	34 %	43 %	48 %
Natural gas	22	21	20
Wind(1)	10	11	10
Hydroelectric and other(1)	5	5	5
Total energy generated	71	80	83
Energy purchased - long-term contracts (renewable)(1)	16	15	15
Energy purchased - short-term contracts and other	12	5	2
Energy purchased - long term contracts (non-renewable)	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, legislative considerations, transmission constraints and wholesale market prices of electricity. PacifiCorp evaluates these factors continuously in order to facilitate economic 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. The Bridger underground mine ceased coal production in November 2021. These mines supplied 18%, 21% and 21% of PacifiCorp's total coal requirements during the years ended December 31, 2023, 2022 and 2021, respectively.

Most of PacifiCorp's coal reserves are held through agreements with the federal Bureau of Land Management and from 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%. To meet applicable standards, PacifiCorp blends its coal with contracted coal and utilizes emissions reduction technologies for controlling SO_2 and other emissions.

For fuel needs at PacifiCorp's coal-fueled generating facilities in excess of coal reserves available, 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 but at significantly higher prices. 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 renewable resources as a viable, economical and environmentally prudent means of supplying electricity and complying with laws and regulations. Renewable resources have low to no emissions and require little or no fossil fuel. 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. In addition to the discussion contained herein regarding repowering activities, refer to "Regulatory Matters" in Item 1 of this Form 10-K.

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 electricity price volatility.

Energy Imbalance Market

PacifiCorp and the California ISO implemented an EIM in November 2014, 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 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 17,100 miles of transmission lines in 10 states, 66,300 miles of distribution lines and 900 substations as of December 31, 2023.

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 plans to build over 2,000 miles of new high-voltage transmission lines, with an estimated cost of approximately $13 billion, primarily in Wyoming, Utah, Idaho and Oregon. The approximately $13 billion estimated cost includes: (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, expected to be 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, expected to be placed in-service in 2024; (g) the 290-mile, 500-kV high-voltage transmission line from the Longhorn substation near Boardman, Oregon to the Hemingway substation near Boise, Idaho (a joint project), expected to be placed in-service in 2026; (h) the 14-mile, 345-kV high-voltage transmission line between the Oquirrh substation and the Terminal substation, expected to be placed in-service in 2024; and (i) remaining segments that are expected to be placed in-service in future years, depending on load growth, economic analysis, IRP results, siting, permitting and construction schedules. 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. Proposed transmission line segments are evaluated to ensure optimal benefits and timing before committing to move forward with permitting and construction. Through December 31, 2023, $4.8 billion had been spent and $2.3 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 will also be 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 elevated fire risk settings, inspections, vegetation management, public safety power shutoff ("PSPS") and wildfire encroachment programs and policies.

Asset Hardening

PacifiCorp has and continues to invest in rebuilding overhead transmission and distribution 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 6,100 miles, or 9%, of PacifiCorp's distribution lines are in fire high consequence areas ("FHCA"), covering approximately 8% of its service territory and approximately 5% of its customer base. Approximately 1,000 miles of transmission lines are in the FHCA. In 2023, the process for updating the risk modeling for the identification of the FHCA was initiated and is on track for finalization in early 2024. It is expected that as the wildfire mitigation program evolves, its targeted programs will cover more service territory.

As of December 31, 2023, all 1,000 miles of transmission lines in the FHCA were mitigated by system relay protection schemes. All 6,100 miles of distribution lines in the FHCA include some form of mitigation including:

- 3,100 miles, or 51%, with bare conductor mitigated by system relay protection schemes;
- 400 miles, or 6%, with new covered conductor; and
- 2,600 miles, or 43%, 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.

Elevated Fire Risk Settings

Elevated fire risk 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 450 weather stations that monitor weather conditions and model the impact to the electrical infrastructure. These weather stations combined with the around-the-clock 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

Within the FHCA PacifiCorp conducts an annual inspection of overhead facilities 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 based on criteria such as system configuration, line structure material, weather conditions and wind. In August 2023, in response to potentially encroaching lightning-caused wildfires in the area at the time, PacifiCorp de-energized transmission lines serving customers in Crescent City and Del Norte County, California, providing a temporary power solution to nearly all of the impacted customers.

<u>Future Generation, Conservation and Energy Efficiency</u>

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 prudency of resources ultimately selected.

In March 2023, PacifiCorp filed its 2023 IRP in Idaho, Oregon and Wyoming. The March 2023 filing was considered informational in Utah. PacifiCorp filed its 2023 IRP (Amended Final) report on May 31, 2023, following a 60-day extended comment period. In October 2023, the IPUC acknowledged the 2023 IRP. In November 2023 through February 2024, PacifiCorp responded to Wyoming, Utah and Oregon stakeholder reply comments as part of the 2023 IRP acknowledgement and related processes.

The 2023 IRP is off cycle with regard to Washington's four-year IRP cycle and has instead been filed in that state as the "Washington Two-Year Progress Report," aligned with the Clean Energy Transformation Act requirements. In October, the WUTC approved a multi-party settlement agreement that resolved challenges to the Clean Energy Implementation Plan ("CEIP").

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. This is pertinent to maintaining a March 31, 2025 filing date for the 2025 IRP. Related 2025 IRP filing dates are also extended, however, the filing dates for Washington's CEIP are unchanged.

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. No final shortlist will be announced while the RFP is paused. 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 suspend the RFP included:

- A federal court's stay of the EPA's proposed ozone transport rule.
- Ongoing rulemaking by the EPA regarding greenhouse gas emissions.
- Wildfire risk and associated liability across PacifiCorp's six-state service area and throughout the West.
- Evolving extreme weather risks that necessitate further decision-making regarding PacifiCorp's operational and resource requirements.

As of this filing, PacifiCorp has made no decision specific to the 2022AS RFP's reinstatement or termination. Next steps regarding the 2022 AS RFP will be further informed by the findings from the 2023 IRP updates scheduled for release in the first quarter of 2024.

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. During 2023, PacifiCorp spent $178 million on these DSM programs, resulting in an estimated 642,569 MWhs of first-year energy savings and an estimated 459 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 372 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. The corresponding recovery of costs was approved by the respective state commissions or through PacifiCorp's general rate case process.

Human Capital

Employees

As of December 31, 2023, PacifiCorp had approximately 5,000 employees, of which approximately 2,800 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 owns all of the outstanding common stock of MHC Inc. ("MHC"), which is a holding company owning 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 the ownership of MHC. MHC conducts no business other than the ownership of 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 666 Grand Avenue, Des Moines, Iowa 50309-2580 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):

	2023		2022		2021	
Operating revenue:						
Regulated electric	$ 2,673	79 %	$ 2,988	74 %	$ 2,529	71 %
Regulated gas	713	21	1,030	26	1,003	28
Other	7	—	7	—	15	1
Total operating revenue	$ 3,393	100 %	$ 4,025	100 %	$ 3,547	100 %
Operating income:						
Regulated electric	$ 471	90 %	$ 372	85 %	$ 358	86 %
Regulated gas	50	10	66	15	58	14
Total operating income	$ 521	100 %	$ 438	100 %	$ 416	100 %

MidAmerican Energy was incorporated under the laws of the state of Iowa in 1995 and its principal executive offices are located at 666 Grand Avenue, Des Moines, Iowa 50309-2580, 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:

	2023		2022		2021	
Iowa	27,554	93 %	27,024	92 %	25,909	92 %
Illinois	1,827	6	1,970	7	1,895	7
South Dakota	294	1	296	1	270	1
	29,675	100 %	29,290	100 %	28,074	100 %

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:

	2023		2022		2021	
GWhs sold:						
Residential	6,759	15 %	7,006	15 %	6,718	15 %
Commercial	3,992	9	4,017	9	3,841	9
Industrial	17,307	39	16,646	35	15,944	36
Other	1,617	3	1,621	3	1,571	4
Total retail	29,675	66	29,290	62	28,074	64
Wholesale	15,129	34	17,964	38	16,011	36
Total GWhs sold	44,804	100 %	47,254	100 %	44,085	100 %
Average number of retail customers (in thousands):						
Residential	703	86 %	697	86 %	690	86 %
Commercial	101	12	99	12	98	12
Industrial	2	—	2	—	2	—
Other	14	2	15	2	14	2
Total	820	100 %	813	100 %	804	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 26%, 25% and 24% of total retail electric sales in 2023, 2022 and 2021, respectively. Sales to electronic data storage customers included in the 10 largest customers comprised 20%, 18% and 16% of total retail electric sales in 2023, 2022 and 2021, 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. 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, which is 465 MWs greater than the previous record hourly peak demand of 5,386 MWs set August 2, 2022.

Generating Facilities and Fuel Supply

MidAmerican Energy has ownership interest in a diverse portfolio of generating facilities. The following table presents certain information regarding MidAmerican Energy's owned generating facilities as of December 31, 2023:

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	475	475
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
Arbor Hill	Greenfield, IA	Wind	2018-2020	316	316

Generating Facility	Location	Energy Source	Year Installed / Repowered[1]	Facility Net Capacity (MWs)[2]	Net Owned Capacity (MWs)[2]
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	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	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
				7,392	7,392
COAL:					
Louisa	Muscatine, IA	Coal	1983	746	656
Walter Scott, Jr. Unit No. 3	Council Bluffs, IA	Coal	1978	706	558
Walter Scott, Jr. Unit No. 4	Council Bluffs, IA	Coal	2007	806	481
Ottumwa	Ottumwa, IA	Coal	1981	724	376
George Neal Unit No. 3	Sergeant Bluff, IA	Coal	1975	510	367
George Neal Unit No. 4	Salix, IA	Coal	1979	647	263
				4,139	2,701
NATURAL GAS AND OTHER:					
Greater Des Moines	Pleasant Hill, IA	Gas	2003-2004	510	510
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	145	145
River Hills	Des Moines, IA	Gas	1966-1967	115	115
Coralville	Coralville, IA	Gas	1970	64	64
Moline	Moline, IL	Gas	1970	61	61
27 portable power modules	Various	Oil	2000	54	54
Parr	Charles City, IA	Gas	1969	33	33
				1,326	1,326
NUCLEAR:					
Quad Cities Unit Nos. 1 and 2	Cordova, IL	Uranium	1972	1,809	452
SOLAR:					
Holliday 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				14,811	12,016

(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:

	2023	2022	2021
Wind and other renewable[1]	55 %	58 %	52 %
Coal	22	21	27
Nuclear	8	8	9
Natural gas	5	3	3
Total energy generated	90	90	91
Energy purchased - short-term contracts and other	9	9	8
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 transportation costs, weather, environmental considerations, transmission constraints, and wholesale market prices of electricity. MidAmerican Energy evaluates these factors continuously in order to facilitate economic 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 IUB, facilities accounting for 89% of MidAmerican Energy's wind-powered generating capacity in-service at December 31, 2023, 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, or plans to repower, 2,357 MWs of wind-powered generating facilities for which PTCs had expired by the end of 2022.

Of the 7,617 MWs (nameplate capacity) of wind-powered generating facilities in-service as of December 31, 2023, 7,416 MWs were generating PTCs, including 2,316 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 totaling $681 million, $710 million and $574 million in 2023, 2022 and 2021, respectively, of which —%, 4% and 12%, respectively, were included in the Iowa EAC.

Coal

All of the coal-fueled generating facilities operated by MidAmerican Energy are fueled by low-sulfur, western 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. A substantial share of MidAmerican Energy's expected coal supply requirements for 2024 and 2025 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 all of the MidAmerican Energy-operated coal-fueled generating facilities other than the George Neal Energy Center. 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 for short-haul delivery 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 or conversion, enrichment or 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 June 1, 2027.

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. markets and can contract with several other utilities in the region. MidAmerican Energy utilizes financial swaps and physical fixed-price electricity sales and purchases contracts to reduce its exposure to electricity price volatility.

MidAmerican Energy's decisions regarding additions to or reductions of its generation portfolio may be impacted by the MISO's minimum reserve margin requirement. 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. The MISO's reserve requirements for the 2023-2024 planning year were 7.4% for summer 2023, 14.9% for fall 2023, 25.5% for winter 2023-2024 and 24.5% for spring 2024. For the summer peak demand season, MidAmerican Energy's owned and contracted capacity accredited for the 2023-2024 MISO capacity auction was 5,984 MWs compared to a peak demand obligation of 5,332 MWs, or a reserve margin of 12.2%. Additionally, MidAmerican Energy had more than adequate reserve margin for the fall, winter and spring seasons when peak demands are typically lower. Some of the excess capacity may be sold through bilateral or MISO capacity auction transactions. The reserve requirements for the 2024-2025 planning year will be 9.0% for summer 2024, 14.2% for fall 2024, 27.4% for winter 2024-2025 and 26.7% for spring 2025. 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.

Transmission and Distribution

MidAmerican Energy's transmission and distribution systems included 4,700 circuit miles of transmission lines in four states, 25,500 circuit miles of distribution lines and 340 substations as of December 31, 2023. 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 economic 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 2023, 58% 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 24,900 miles of natural gas main and service lines as of December 31, 2023.

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:

	2023	2022	2021
Iowa	75 %	76 %	76 %
South Dakota	14	14	13
Illinois	10	9	10
Nebraska	1	1	1
	100 %	100 %	100 %

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:

	2023	2022	2021
Residential	45 %	47 %	44 %
Commercial(1)	21	22	20
Industrial(1)	5	5	5
Total retail	71	74	69
Wholesale(2)	29	26	31
	100 %	100 %	100 %
Total Dths of natural gas sold (in thousands)	106,912	119,508	111,916
Total Dths of transportation service (in thousands)	106,422	102,827	112,631
Total average number of retail customers (in thousands)	796	789	781

(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.

On December 22, 2022, MidAmerican Energy recorded its all-time highest peak-day delivery through its distribution system of 1,325,160 Dths. This peak-day delivery consisted of 72% traditional retail sales service and 28% transportation service. MidAmerican Energy's 2023/2024 winter heating season preliminary peak-day delivery as of January 31, 2024, was 1,309,311 Dths, reached on January 15, 2024. 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 IUB 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 2023/2024 winter heating season preliminary peak-day of January 15, 2024, supply sources used to meet deliveries to traditional retail sales service customers included 51% from purchases delivered on interstate pipelines, 37% from interstate pipeline storage services and 12% 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. IUB 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 2023, $43 million was expensed for MidAmerican Energy's energy efficiency programs, which resulted in estimated first-year energy savings of 119,000 MWhs of electricity and 113,000 Dths of natural gas and an estimated peak load reduction of 406 MWs of electricity and 1,641 Dths per day of natural gas.

Human Capital

Employees

All of MidAmerican Funding's employees are employed by MidAmerican Energy. As of December 31, 2023, 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 2023, 86% 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):

	2023		2022		2021	
Operating revenue:						
Electric	$ 1,194	83 %	$ 1,025	86 %	$ 848	88 %
Gas	237	17	168	14	117	12
Total operating revenue	$ 1,431	100 %	$ 1,193	100 %	$ 965	100 %
Operating income:						
Electric	$ 133	88 %	$ 146	88 %	$ 148	89 %
Gas	19	12	19	12	19	11
Total operating income	$ 152	100 %	$ 165	100 %	$ 167	100 %

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:

	2023		2022		2021	
Nevada Power:						
GWhs sold:						
Residential	9,584	41 %	10,299	42 %	10,415	44 %
Commercial	4,807	20	4,904	21	4,838	21
Industrial	5,827	25	5,630	23	5,270	22
Other	179	1	191	1	198	1
Total fully bundled	20,397	87	21,024	87	20,721	88
Distribution only service	2,831	12	2,786	11	2,646	11
Total retail	23,228	99	23,810	98	23,367	99
Wholesale	230	1	586	2	356	1
Total GWhs sold	23,458	100 %	24,396	100 %	23,723	100 %
Average number of retail customers (in thousands):						
Residential	899	89 %	886	89 %	871	88 %
Commercial	114	11	113	11	112	12
Industrial	2	—	2	—	2	—
Total	1,015	100 %	1,001	100 %	985	100 %
Sierra Pacific:						
GWhs sold:						
Residential	2,655	23 %	2,747	22 %	2,769	23 %
Commercial	2,998	25	3,124	26	3,056	26
Industrial	2,684	23	2,867	23	3,716	31
Other	11	—	13	—	15	—
Total fully bundled	8,348	71	8,751	71	9,556	80
Distribution only service	2,829	24	2,757	23	1,639	14
Total retail	11,177	95	11,508	94	11,195	94
Wholesale	621	5	741	6	656	6
Total GWhs sold	11,798	100 %	12,249	100 %	11,851	100 %
Average number of retail customers (in thousands):						
Residential	326	87 %	322	87 %	316	87 %
Commercial	50	13	49	13	49	13
Total	376	100 %	371	100 %	365	100 %

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. On July 21, 2023, customer usage of electricity caused an hourly peak demand of 6,311 MWs on Nevada Power's electric system, which is 11 MWs more than the record hourly peak demand of 6,300 MWs set July 9, 2021. On July 21, 2023, customer usage of electricity caused an hourly peak demand of 1,825 MWs on Sierra Pacific's electric system, which is 281 MWs less than the record hourly peak demand of 2,106 MWs set July 12, 2021.

Generating Facilities and Fuel Supply

The Nevada Utilities have ownership interest in a diverse portfolio of generating facilities. The following table presents certain information regarding the Nevada Utilities' owned generating facilities as of December 31, 2023:

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	1,102	1,102
Harry Allen	Las Vegas, NV	Natural gas	1995-2011	628	628
Higgins	Primm, NV	Natural gas	2004	602	602
Silverhawk	Las Vegas, NV	Natural gas	2004	590	590
Las Vegas	Las Vegas, NV	Natural gas	1994-2003	272	272
Sun Peak	Las Vegas, NV	Natural gas/oil	1991	210	210
				4,622	4,622
RENEWABLES:					
Nellis	Las Vegas, NV	Solar	2015	15	15
Goodsprings	Goodsprings, NV	Waste heat	2010	5	5
				20	20
Total Available Generating Capacity				4,642	4,642
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
				1,087	1,087
COAL:					
Valmy Unit Nos. 1 and 2	Valmy, NV	Coal	1981-1985	522	261
RENEWABLES:					
Ft. Churchill	Yerington, NV	Solar	2015	20	20
Total Available Generating Capacity				1,629	1,368
Total NV Energy Available Generating Capacity				6,271	6,010
PROJECTS UNDER CONSTRUCTION:					
Silverhawk peakers project	Las Vegas, NV	Natural Gas	Est. 2024	444	444
Dry Lake (2)	Dry Lake, NV	Solar	Est. 2024	150	150
				6,865	6,604

(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) In addition to the 150-MW solar photovoltaic facility, Dry Lake has 100 MW of co-located battery energy storage that will be developed in Clark County, Nevada with commercial operation expected by 2024.

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.

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

	2023	2022	2021
Nevada Power:			
Total energy generated(1) - natural gas	65 %	60 %	64 %
Energy purchased - long-term contracts (renewable)(2)	24	23	19
Energy purchased - long-term contracts (non-renewable)	5	9	10
Energy purchased - short-term contracts and other	6	8	7
	100 %	100 %	100 %
Sierra Pacific:			
Natural gas	44 %	41 %	43 %
Coal	8	11	11
Total energy generated(1)	52	52	54
Energy purchased - long-term contracts (renewable)(2)	32	28	17
Energy purchased - long-term contracts (non-renewable)	9	11	14
Energy purchased - short-term contracts and other	7	9	15
	100 %	100 %	100 %

(1) Energy generated from renewable generating facilities is not meaningful.

(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 transportation costs; weather; environmental considerations; transmission constraints; and wholesale market prices of electricity. The Nevada Utilities evaluate these factors continuously in order to facilitate economic 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 policy setting (or 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 2,937 MWs with contract termination dates ranging from 2024 to 2067. Included in these contracts are 2,852 MWs of capacity from renewable energy, of which 818 MWs of capacity are under development or construction and not currently available. Sierra Pacific has entered into contracts with a total capacity of 1,098 MWs with contract termination dates ranging from 2024 to 2053. Included in these contracts are 1,086 MWs of capacity from renewable energy, of which 140 MWs of capacity are owned and 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 2023, natural gas supply net purchases averaged 299,343 and 154,897 Dths per day with the winter period contracts averaging 290,172 and 195,554 Dths per day and the summer period contracts averaging 305,813 and 126,209 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 Burlington Northern Sante Fe Railroad Company to ship coal from western Montana that expires December 31, 2024. The Valmy generating facility, Sierra Pacific's remaining facility requiring coal, has an approved retirement date of December 2025. Sierra Pacific has 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. 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, 14,300 miles of distribution lines and 220 substations as of December 31, 2023. Sierra Pacific's transmission and distribution systems included approximately 4,200 miles of transmission lines, 9,600 miles of distribution lines and 210 substations as of December 31, 2023.

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 $3.1 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 Yerington, 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, 2023, $187 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 elevated fire risk settings, inspections, vegetation management, enhancement to situational awareness to include implementation of wildfire alert cameras and weather stations in extreme fire-risk areas and public safety outage management ("PSOM") programs and policies.

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, Tier1E - Elevated ("Tier 1E"), Tier 2 (high) and Tier 3 (extreme).

Approximately 2,730 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, 2023, the 2,730 miles of transmission and distribution lines in Tier 1E, Tier 2 and Tier 3 HTAs were as follows:

- 1,964 miles, or 72%, 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 completion by the end of 2024;
- 16 miles, or 1%, with new covered conductor miles; and
- 750 miles, or 27%, 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.

Elevated Fire Risk Settings

Elevated fire risk 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 11 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

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 2023, the Nevada Utilities continued to actively utilize the PSOM program to address extreme-risk weather conditions.

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 its 2021 Integrated Resource Plan Fourth Amendment filed November 30, 2022, NV Energy requested approval for a 20-megawatt Advanced Geothermal System power purchase agreement with Eavor, a 120-megawatt geothermal portfolio power purchase agreement with Ormat, and the development of a company-owned, 200-megawatt, 800 megawatt-hour grid-tied battery energy storage system in Sierra Pacific's territory at Valmy station. In June 2023, the PUCN granted in part and denied in part the fourth amendment as delineated in the order.

In compliance with SB 448, the Nevada Utilities filed their second and third amendments to the 2021 joint IRP in July and September 2022, respectively. The Nevada Utilities requested an approval to amend the Demand Side Plan for the action period for 2022-2024 in July's filing and requested in September an approval of a DRP amendment to implement the state's first Transportation Electrification Plan ("TEP") and approve proposed tariffs and schedules to implement the TEP. In November 2022, the Nevada Utilities filed an all-party settlement stipulation of the second amendment to the IRP, resolving all issues. In March 2023, the PUCN issued an order accepting the stipulation, granting in part and denying in part the Joint Application as modified by the Order and the Stipulation, accepting in part, deeming inadequate in part, and modifying the third amendment to the Joint IRP, and approving certain programs in the TEP, authorizing a lower program budget of $70 million and ordering specific caps on the program management and contingency budget amounts. The unapproved programs have been deferred for approval in future TEP filings. The PUCN also granted regulatory asset treatment of the approved program costs. In April 2023, interveners filed a petition for reconsideration of the PUCN's March 2023 order. In May 2023, the PUCN granted in part and denied in part the petition for reconsideration and affirmed the March 2023 order.

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 seeks, in part (1) to convert the existing coal fueled plant at North Valmy Generating Station to a cleaner natural gas fueled plant (2) to construct 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 a 149 MW photovoltaic and 149 MW battery energy storage system known as the 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 with an order expected in 2024.

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 2023, Nevada Power spent $46 million on energy efficiency programs, resulting in an estimated 225,753 MWhs of electric energy savings and an estimated 156 MWs of electric peak load management. During 2023, Sierra Pacific spent $13 million on energy efficiency programs, resulting in an estimated 53,195 MWhs of electric energy savings and an estimated 25 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 2023, 6% 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 3,600 miles of natural gas mains and service lines as of December 31, 2023.

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:

	2023	2022	2021
Residential	52 %	55 %	53 %
Commercial[1]	26	28	28
Industrial[1]	12	11	10
Total retail	90	94	91
Wholesale[2]	10	6	9
	100 %	100 %	100 %
Total Dths of natural gas sold (in thousands)	23,613	20,622	20,050
Total Dths of transportation service (in thousands)	1,453	1,576	1,850
Total average number of retail customers (in thousands)	183	180	177

(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, 47-56% of Sierra Pacific's regulated natural gas revenue is reported in the months of December through March.

On January 31, 2023, Sierra Pacific recorded its highest peak-day natural gas delivery of 160,974 Dths, which is 2,600 Dths less than the record peak-day delivery of 163,574 Dths set on December 9, 2013. This peak-day delivery consisted of 95% traditional retail sales service and 5% transportation service.

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, 2023, 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, 2023, Sierra Pacific had approximately 1,000 employees, of which approximately 500 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 which owns 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 owns 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, a hydrocarbon exploration and development business that is focused on developing integrated upstream gas projects in Europe and Australia ("CE Gas") and ownership interests in 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 2023, E.ON and certain of its affiliates and British Gas Trading Limited represented 19% and 15%, 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:

	2023		2022		2021	
GWhs distributed:						
Residential	11,638	38 %	11,880	37 %	13,334	40 %
Commercial	3,534	11	3,737	12	3,643	10
Industrial	15,655	50	16,239	50	16,424	49
Other	279	1	301	1	318	1
	31,106	100 %	32,157	100 %	33,719	100 %
Number of end-users (in thousands):	3,954		3,953		3,941	

As of December 31, 2023, the combined electricity distribution network of the Northern Powergrid Distribution Companies included approximately 17,100 miles of overhead lines, 44,000 miles of underground cables and 790 major substations.

BHE PIPELINE GROUP (EASTERN ENERGY GAS AND EGTS)

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 21.1 Bcf of natural gas per day, transported approximately 15% of the total natural gas consumed in the U.S. during 2023 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.

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 ownership of 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 and storage pipelines 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 pipeline system located in South Carolina and Georgia. Eastern Energy Gas also owns a 50% equity interest in Iroquois Gas Transmission System L.P. ("Iroquois"). Iroquois owns and operates an interstate natural gas pipeline 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 Dth 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 prior to September 1, 2023, owned a 25% limited partner interest in the Cove Point LNG export, import and storage facility. On September 1, 2023, Eastern Energy Gas completed its acquisition of 50% of the limited partner interests in Cove Point from DEI, and accordingly, owns an aggregate of 75% of the limited partner interests and continues to own 100% of the general partner interest of Cove Point. BHE GT&S also operates and has ownership 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 12.6 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 9.9 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 2023, BHE GT&S delivered over 2.1 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, 2023, 84% of BHE GT&S' transmission capacity is subscribed, including 79% under long-term contracts and 5% on a year-to-year basis, and 100% of EGTS' storage capacity is subscribed, including 97% under long-term contracts. As of December 31, 2023, the weighted average remaining contract term for Eastern Energy Gas' and EGTS' firm transmission contracts is seven years and five years, respectively, and EGTS' storage contracts is four 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):

	2023			2022		
Transmission	$	881	39 %	$	849	35 %
LNG		796	36		790	33
Storage		329	15		316	13
Gas, liquids and other sales		233	10		447	19
Total operating revenue	$	2,239	100 %	$	2,402	100 %

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 2023, BHE GT&S had two customers that each accounted for greater than 15% of its operating revenue and its 10 largest customers accounted for 48% 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, 2023, Eastern Energy Gas had approximately 1,500 employees, consisting of approximately 1,200 natural gas operations employees and 300 corporate services employees. As of December 31, 2023, approximately 600 employees were covered by a union contract with the Utility Workers Union of America.

As of December 31, 2023, EGTS had approximately 1,300 employees, consisting of approximately 1,000 natural gas operations employees and 300 corporate services employees. As of December 31, 2023, 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 6.3 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 2,362 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 1.4 Tcf of natural gas to its customers in 2023.

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, 2023, approximately 72% of Northern Natural Gas' customers' entitlement in the Market Area have terms beyond 2026 and approximately 49% beyond 2027. As of December 31, 2023, the weighted average remaining contract term for Northern Natural Gas' Market Area firm transportation contracts is six 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 five 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 five years.

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

	2023		2022		2021	
Transportation:						
Market Area	$ 815	65 %	$ 688	62 %	$ 658	61 %
Field Area	249	22	210	18	177	17
Total transportation	1,064	87	898	80	835	78
Storage	113	9	97	9	94	9
Total transportation and storage revenue	1,177	96	995	89	929	87
Gas, liquids and other sales	49	4	123	11	143	13
Total operating revenue	$ 1,226	100 %	$ 1,118	100 %	$ 1,072	100 %

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 2023, 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 64% 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 operates 1,400 miles of mainline natural gas pipelines, 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. The mainline pipeline 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 36-inch diameter pipeline and 100 miles of various laterals that connect to the mainline. Kern River primarily transports natural gas for utilities, municipalities, energy marketing companies, electric generating companies and other industrial and commercial users.

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, 2023, approximately 87% of Kern River's design capacity, including seasonal Bell-Curve, totaled 2,345,381 Dths per day and 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 81% 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 February 2024 and December 2045 and have a weighted-average remaining contract term of over eight years. As of December 31, 2023, 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.

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 2023, Kern River had two 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, ownership 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 Canada and BHE U.S. Transmission's existing physical generation assets on the Montana Alberta Tie Line. Operations are set to commence in January 2025.

BHE Canada

BHE Canada primarily owns 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, 2023, 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 that links Alberta with the North American western interconnected system, interconnection with Saskatchewan's transmission system and interconnection with Montana's transmission system.

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 Alberta's interconnected electrical system. In January 2022, the AESO released the 2022 Long-Term Transmission Plan. Updated every two years, 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 2022 Long-Term Transmission Plan identifies C$1.3 billion in transmission projects over a 10-year period, which results in C$150 million to C$200 million per year on average over that 10-year period. This results in a cumulative transmission rate impact of C$2 per MWh for the first five to eight years, increasing to C$3 per MWh after 15 years. The Long-Term Transmission Plan identifies approximately C$900 million of projects in AltaLink's service territory with in-service dates before 2030. On November 15, 2023, the AESO issued a preliminary update on the 2024 Long-term Outlook. The AESO is re-evaluating scenarios to include decarbonization by 2050, as well as decarbonization by 2035. AltaLink and other stakeholders provided feedback to the AESO which was published on the AESO's website on December 8, 2023. The final 2024 Long-term Outlook is expected in the second quarter of 2024. The next Long-Term Transmission Plan is expected to be completed in the first quarter of 2025.

Wildfire Risk

Alberta may experience a heightened incidence of wildfires, or wildfire severity due to climate change and other factors. AltaLink cannot predict how the AUC will respond to such heightened incidence, or how the AUC might treat recovery of its investment or damages and whether or not it might impose fines. AltaLink has a robust set of procedures to address wildfire risk. AltaLink reviews and updates these procedures based on the best practices in other jurisdictions. AltaLink applies to the AUC for approval for funds to implement these procedures and mitigation investments. Additional requirements may be imposed by the regulator or legislators in response to heightened risk. AltaLink is monitoring all changes to its regulatory framework and will respond to any such changes as they arise. Electricity transmission facilities may also start wildfires as a result of causes such as equipment operation or failure, trees contacting transmission lines, or lightning strikes on transmission lines or equipment.

Wildfire Mitigation Plans

AltaLink has developed and implemented detailed wildfire mitigation plans for its service territory since 2019. AltaLink files and gets AUC approval for its wildfire mitigation plan as part of its GTA process. AltaLink has received approval for its wildfire mitigation plan in both the 2019-2021 and 2022-2023 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 fire risk operating practices and policies, including inspections, recloser blocking procedures, and PSPS.

AltaLink filed an amendment to its 2024-2025 GTA with additional measures to proactively expand and accelerate its 2024-2025 Wildfire Mitigation Plan in response to the increase in wildfire risk to Albertans and AltaLink's critical infrastructure which delivers reliable electricity to customers. AltaLink proposes a catastrophic wildfire damages deferral account for damages in excess of commercial insurance. Despite its actions, AltaLink may be liable for firefighting costs, damages to personal property, structures, and natural resources, fines, and third-party claims including for personal injuries in connection with such fires. These costs could substantially exceed insurance coverage, if any, and such amounts may not be approved by the AUC for recovery, in whole or in part, through increased tariff revenues.

Asset Hardening and Vegetation Management

AltaLink has and continues to invest in specific asset improvements targeted to reduce the risk of wildfire ignition from AltaLink's operations. These hardening efforts reduce the likelihood of AltaLink's transmission lines to spark a wildfire at locations of high fire risk.

Approximately 15% of AltaLink's transmission lines are in High Risk Fire Areas ("HRFAs"). Of these HRFA lines, 27% are in urban areas and communities, 23% are in forested areas, with the remaining 50% located in agricultural, grassland or native prairie.

Situational Awareness, Meteorology, and Risk Modeling

AltaLink uses available integrated meteorology and camera systems available from the Alberta Government and has installed 13 of 17 planned 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 has established a Daily Hazard Forecast Report provided to the organization and field crews as well as 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 modeling in 2024. AltaLink is developing further enhanced fire weather modeling tools in 2024. AltaLink has completed 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 an annual basis. For lines located in HRFAs, inspection frequencies are twice per year to review structure and vegetation conditions.

Public Safety Power Shutoff

A PSPS is an operating protocol used as a preventative measure of last resort during periods of extreme wildfire risk where a transmission line or lines would be de-energized 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 in consideration of 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 has and continues to conduct stakeholder engagement and exercises related to its PSPS process.

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, 2023, had total assets of $3.8 billion. ETT's transmission system includes approximately 2,000 miles of transmission lines and 47 substations as of December 31, 2023. Prairie Wind Transmission, LLC, owns and operates a 108-mile, 345-kV transmission project in Kansas having total assets of $131 million as of December 31, 2023.

Generating Facilities

BHE Transmission has ownership interests in the following generating facilities as of December 31, 2023:

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	Montana	Wind	2012	2026	Morgan Stanley	189	189
Glacier 1	Montana	Wind	2008	N/A	N/A	107	107
Glacier 2	Montana	Wind	2009	N/A	N/A	103	103
						529	529
NATURAL GAS:							
Nat-1	Alberta	Natural gas	2015	N/A	N/A	20	20
						20	20
Total Available Generating Capacity						549	549

(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' ownership of Facility Net Capacity.

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, 2023:

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 I	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
						1,684	1,536
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	2024	SDG&E	50	50
						947	898
GEOTHERMAL:							
Imperial Valley Projects	California	Geothermal	1982-2000	(3)	(3)	345	345
						345	345
HYDROELECTRIC:							
Wailuku	Hawaii	Hydroelectric	1993	2028	HELCO	10	10
						10	10
Total Available Generating Capacity						5,293	5,096
PROJECTS UNDER CONSTRUCTION							
Solar Star 3 & 4	California	Solar	Est. 2024			48	48
						5,341	5,144

(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"); San Diego Gas & Electric Company ("SDG&E"); and Hawaii Electric Light Company, Inc. ("HELCO").

(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.

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

	2023		2022		2021	
Solar	$ 427	26 %	$ 477	28 %	$ 468	27 %
Wind	276	16	228	13	160	10
Geothermal	210	12	212	12	178	11
Hydro	4	—	5	—	32	2
Natural gas	105	6	71	4	143	9
Retail energy services	688	40	744	43	680	41
Total operating revenue	$ 1,710	100 %	$ 1,737	100 %	$ 1,661	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 900 offices in 34 states and the District of Columbia with approximately 41,000 real estate agents under 50 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 approximately 300 franchisees and over 1,500 brokerage offices with approximately 48,000 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 is also included in the mechanism. Beginning in 2021, the mechanism includes a true-up of PTCs 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.
		Effective January 1, 2021, 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.
		RAC 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.

State Regulator	Base Rate Test Period	Adjustment Mechanism
		Effective January 1, 2021, Annual Wildfire Mitigation and Vegetation Management Cost Recovery Mechanism approved through 2024 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. After 2024, the mechanism will be assessed to determine whether continued use is warranted. Effective May 10, 2023, the WMP AAC was approved to recover the capital and operations and maintenance costs associated with implementation and operation of PacifiCorp's Oregon Wildfire Mitigation Plan beginning with the 2022 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 SO_2 revenue adjustment mechanism to provide for recovery or refund of 100% of any difference between actual REC and SO_2 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). Beginning in 2021, the mechanism includes a true-up of PTCs at 100%. 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, subject to an earnings test. Under the earnings test, 50% of any proportional excess earnings over PacifiCorp's authorized return on equity is returned to customers in addition to any surcharge or surcredit related to the revenue variance. The earnings test is asymmetrical, and adjustments are not made when PacifiCorp earns at or below authorized returns on equity. 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 IUB review and subject to refund, on or after 10 days of filing a request for higher base rates. If the IUB 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 IUB prior to the construction of certain types of new generating facilities. Pursuant to this law, MidAmerican Energy has applied for and obtained IUB 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, 2023. These ratemaking principles established cost caps for the projects, below which such costs are deemed prudent by the IUB 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, 2023, the generating facilities in-service totaled $7.5 billion, or 35%, 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 IUB 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, 2023, 5,225 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 IUB 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, which, among other items, reduced the state of Iowa corporate tax rate in stages from 12% to its current 8.4%, and the impacts of such changes are included in the Iowa tax expense revision mechanism.

NV Energy (Nevada Power and Sierra Pacific)

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 753 MWs.

Natural Disaster Protection Plan ("NDPP")

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 are pending.

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 $1.5 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 ownership 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, Nevada Utilities, Idaho Power Company and NorthWestern Energy 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 is under review by the FERC. 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% ownership 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 ("NWPA"), 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 NWPA, 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 in order 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 $450 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 $83 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 $10 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 $450 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, 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.

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 prudency 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 ("EWG") under the Energy Policy Act, while the Community Solar Gardens, Imperial Valley and Wailuku independent power projects are currently certified as Qualifying Facilities ("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 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 2021, was supplemented in July 2022 and an order accepting it was issued in January 2023. 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, 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 the 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 2023, PacifiCorp filed its energy balancing account application to recover deferred net power costs from 2022. The filing requested a rate increase of $98 million, or 4.6%, which was effective on an interim basis July 1, 2023. The UPSC held a hearing in January 2024 and an order is expected in February 2024.

In June 2023, PacifiCorp filed its annual wildland fire cost and compliance report with the UPSC, which reported on calendar year 2022 wildland fire mitigation activities. The report included a request to recover $7 million in deferred costs associated with implementing the wildland fire mitigation plan incremental to those included in base rates. PacifiCorp proposed to recover the amounts over one year. Intervening parties requested a hearing to review the rate request, which was held in October 2023. In November 2023, the UPSC issued an order denying the rate request without prejudice. PacifiCorp may continue to defer the 2022 wildland fire mitigation plan costs, and the UPSC may approve recovery of these costs, if PacifiCorp is able to provide substantial evidence that the claimed costs are not already recovered through base rates. PacifiCorp will request recovery as part of its upcoming general rate case expected to be filed in April 2024.

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. Until the independent evaluator completes its work reviewing the third-party studies that contain the estimated decommissioning and other closure costs and the OPUC issues an order, there will be no change to rates related to this filing.

In July 2022, PacifiCorp filed an application requesting approval of an automatic adjustment clause with a balancing account to recover costs associated with implementing PacifiCorp's wildfire protection plan in Oregon. Per formal rulemaking at the OPUC, the wildfire protection plan was changed to be known as the wildfire mitigation plan, resulting in the requested automatic adjustment clause being referred to as the Wildfire Mitigation Plan Automatic Adjustment Clause ("WMP AAC"). In December 2022, a stipulation with certain parties was filed agreeing to the establishment of an automatic adjustment clause. In May 2023, the OPUC approved the stipulation, which resulted in an overall annual increase of $20 million, or 1.6%, effective May 24, 2023 for estimated 2022 incremental operation and maintenance costs in excess of those reflected in base rates as a result of the last general rate case. In June 2023, PacifiCorp filed its WMP AAC to recover remaining 2022 deferred operations and maintenance costs, projected incremental 2023 operations and maintenance costs and capital costs incremental to amounts previously included in general rate case filings. The filing requested a rate increase of $27 million over the existing amount approved in May 2023, to become effective November 5, 2023. When combined with the previously approved increase, the rate schedule would be set to recover $47 million. In October 2023, in response to discussions with the OPUC staff, PacifiCorp requested the effective date for the WMP AAC shift to December 13, 2023, to allow more time for the OPUC staff to review the filing, and in November 2023, PacifiCorp requested the effective date move to January 10, 2024, to allow PacifiCorp to participate in the public meeting when the matter is brought before the OPUC. In January 2024, PacifiCorp filed a supplemental filing reducing the requested rate increase to $25 million, or 1.4%, and in the public meeting the OPUC approved the rate increase with an effective date of January 10, 2024.

In April 2023, PacifiCorp filed its TAM requesting approval to update net power costs for 2024. The filing requested a rate increase of $164 million, or 9.5%, to become effective January 1, 2024. In July 2023, PacifiCorp updated its filing to reduce the requested rate increase to $131 million to reflect changes in PacifiCorp's forecast net power costs for 2024. In September 2023, a stipulation with certain intervening parties was filed settling substantially all issues in the 2024 TAM and in October 2023, the OPUC issued an order approving the stipulation, subject to final updates and excluding costs associated with the Washington Cap and Invest program. The final update, filed in November 2023, resulted in a rate increase of $150 million, or 8.7%, effective January 1, 2024.

In May 2023, PacifiCorp filed its 2022 PCAM requesting recovery of the difference between actual power costs and base power costs established in the 2022 TAM. The filing requested recovery of $131 million, which PacifiCorp proposed to recover over a two-year period with interest, resulting in a rate increase of $69 million, or 4.0%, effective January 1, 2024. In October 2023, a stipulation was filed providing for the requested amounts. In December 2023, the OPUC issued an order accepting the stipulation. As established in the stipulation, because the combined January 1, 2024 rate increase for residential customers from all January 1 rate changes was less than 15%, the rate effective date of the 2022 PCAM for residential customers remained January 1, 2024.

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 includes 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 February 2024, PacifiCorp filed its TAM requesting approval to update net power costs for 2025. The filing requests a rate decrease of $18 million, or 1.0%, subject to updates throughout the course of the proceeding, to become effective January 1, 2025.

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 includes 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. As a result of the updates, the requested rate increase has been revised to $137 million, or 21.1%. In November 2023, the WPSC approved a rate increase of $54 million, or 8.3%, effective January 1, 2024. The approved rate increase reflects a reduction in the requested return on equity compared to what was sought by PacifiCorp, the exclusion of the increased insurance premium costs that will be addressed outside of the general rate case and a reduction in net power costs determined by the WPSC. The approved rate increase also excludes from the net power costs 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 2023, PacifiCorp filed its ECAM, REC and RRA to recover deferred net power costs from 2022. The combined filing requested a rate increase of $49 million, or 7.4%, which was effective on an interim basis July 1, 2023. In October 2023, PacifiCorp filed rebuttal testimony updating the ECAM calculation. As a result of the updates, the requested combined rate increase was revised to $42 million, or 6.3%. In December 2023, a stipulation and settlement agreement was filed, reflecting a combined rate increase of $40 million, or 6.0%. The WPSC approved the stipulation in December 2023, with an effective date of January 1, 2024.

Washington

In March 2023, PacifiCorp filed a general rate case requesting a two-year rate plan with a rate increase of $27 million, or 6.6%, to become effective March 1, 2024, and a second rate increase of $28 million, or 6.5%, to become effective March 1, 2025. The requested rate increase includes 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. As a result of the updates, the requested rate increases have been revised to $19 million, or 4.6%, to become effective March 1, 2024, and $22 million, or 5.2%, to become effective March 1, 2025. In December 2023, a multi-party settlement stipulation was filed updating 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 a final decision from the WUTC is pending.

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 will be evaluated in the adjudicative proceeding that is scheduled for hearing in June 2024.

Idaho

In October 2022, PacifiCorp filed an application for authority to implement the residential rate modernization plan. The plan proposed a five-year transition to increase the monthly customer service charge from $8.00 to $29.25 per month with a corresponding reduction to the energy rate, eliminated the tiered rates, and adjusted the on-peak off-peak period for time-of-day customers. In response to concerns about the combined impact of the proposed changes, PacifiCorp proposed a modification to, rather than elimination of, the tiered rates. In May 2023, the IPUC issued an order approving PacifiCorp's request to increase the customer service charge over five years, to adjust peak periods for time-of-day customers, and to modify the tiered rate structure. The changes to the residential rates became effective June 1, 2023.

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. A decision in the second track is expected by late 2024.

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 $6 million decrease to the GHG rate. In January 2024, PacifiCorp filed a joint motion for approval of the GHG portion of the filing.

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 enable PacifiCorp to preserve its ability to seek recovery in the future in the event the outcome could potentially impact its financial stability. The applications state that PacifiCorp is not seeking recovery of these costs from customers at this time and does not expect to determine if it will seek recovery until the appeals process has concluded. In August 2023, PacifiCorp filed a motion to withdraw without prejudice with the UPSC, and in September 2023, PacifiCorp filed a notice of withdrawal without prejudice with the IPUC. These filings preserve the ability of PacifiCorp to file for deferred accounting treatment when the actual liability costs are more certain.

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 and PacifiCorp anticipates a final order by April 2024, approving the Wildfire Expense Memorandum Account to be able to track costs incurred on or after June 21, 2020.

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 incremental 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.

MidAmerican Energy

Iowa

In June 2023, MidAmerican Energy filed a request with the IUB for an increase in its Iowa retail natural gas rates, which would increase revenue by $39 million annually or increase retail customer's bills by an average of 6.1%. Interim rates of $31 million annually, or an average increase to customer's bills of 4.8%, were effective in June 2023. In January 2024, MidAmerican Energy filed a non-unanimous settlement with the OCA, which would allow for an increase in revenue of $30 million annually, or an average increase to customer's bills of 4.6%. On January 23, 2024, the IUB held a hearing regarding the non-unanimous settlement agreement. MidAmerican Energy expects the IUB to issue an order on the non-unanimous settlement in the first quarter of 2024 with final rates effective in the second quarter of 2024.

Wind PRIME

In January 2022, MidAmerican Energy filed an application with the IUB for advance ratemaking principles for Wind PRIME, which consists of up to 2,042 MWs of new wind generation and up to 50 MWs of solar generation. If all Wind PRIME generation is constructed, MidAmerican Energy will own over 9,300 MWs of wind generation and nearly 200 MWs of solar generation. Wind PRIME is projected to allow MidAmerican Energy to generate renewable energy greater than or equal to all of its Iowa retail customers' annual energy needs. MidAmerican Energy expects to be eligible for 100% PTCs under current tax law for the Wind PRIME projects. In December 2022, MidAmerican Energy, the OCA and the Iowa Business Energy Coalition filed a non-unanimous settlement with the IUB. On April 27, 2023, the IUB issued its final order regarding the application and found that MidAmerican Energy met the statutory requisites for a grant of advance ratemaking principles and granted the application, but rejected the settlement and proposed its own principles for the project. MidAmerican Energy reviewed the order and filed a motion for reconsideration or rehearing on May 17, 2023. On June 15, 2023, the IUB granted the motion for reconsideration and rehearing. In August 2023, MidAmerican Energy, the OCA and the Environmental Intervenors filed a revised non-unanimous settlement with the IUB that included a return on equity of 10.75%. The settlement would also benefit customers by providing a rate decrease through lower retail fuel costs and future rate increase mitigation through accelerated depreciation of generation assets. On December 14, 2023, the IUB issued its final order on rehearing, approving the revised non-unanimous settlement. MidAmerican Energy accepted the ratemaking principles on December 18, 2023, and plans to move forward with the construction of Wind PRIME.

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. Also known as the Right of First Refusal, the law provides 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. To exercise the legal right, MidAmerican Energy must notify the IUB within 90 days of any such approval for the construction of eligible electric transmission lines that it intends to construct, own and maintain. The law still requires an incumbent electric transmission owner to obtain a state franchise from the IUB to construct, erect, maintain or operate an electric transmission line and, upon issuance of a franchise, the incumbent electric transmission owner must provide the IUB an estimate of the cost to construct the eligible electric transmission line and, until the construction is complete, a quarterly report updating the estimated cost to construct the eligible electric transmission line. In October 2020, national transmission interests filed a lawsuit that challenged the law on state constitutional grounds. The suit argues that the law was enacted in violation of the "single-subject" provision of Iowa's state constitution because it was "log-rolled" into a late session appropriations bill and violates the equal protection provision of the Iowa constitution. The State of Iowa defended the law, and MidAmerican Energy and ITC Midwest both intervened and defended the law as well. The Iowa district court dismissed the lawsuit in March 2021 for lack of standing, and the national transmission interests appealed. In June 2022, the Iowa Court of Appeals upheld the district court's decision, after which the national transmission interests asked the Iowa Supreme Court to reconsider. In November 2022, the Iowa Supreme Court granted the motion to reconsider. On March 24, 2023, the Iowa Supreme Court issued an opinion that reversed the lower courts, held the national transmission interests had standing, and remanded the case to the district court to consider the state constitutional claims on their merits. The opinion also imposed a temporary injunction that stayed enforcement of the law pending a decision on the merits. On April 7, 2023, the State of Iowa, acting individually, and MidAmerican Energy and ITC Midwest, acting jointly, filed petitions for rehearing with the Iowa Supreme Court. On April 19, 2023, the national transmission interests filed a reply that (1) expressed its opposition to the petitions for rehearing, (2) asked the Iowa Supreme Court to hold that the injunction specifically applied to and precluded advancement of MidAmerican Energy's Long Range Transmission Projects ("LRTP") Tranche 1 projects, and (3) asked the Iowa Supreme Court to retain the matter and rule on the constitutional claims on the merits without further briefing or argument. On April 26, 2023, the Iowa Supreme Court issued an order that denied the petitions for rehearing without comment and made minor, non-substantive changes to the decision, with no changes to the injunction. On May 30, 2023, the Iowa Supreme Court remanded the case to the district court for further proceedings on the merits, where the national transmission interests filed a motion for summary judgment. The State of Iowa, MidAmerican Energy and ITC Midwest collaborated to resist the motion and submit a cross motion for summary judgment. The Iowa district court held a hearing on the motions for summary judgment on September 29, 2023. On December 4, 2023, the district court issued an order that granted LS Power's motion for summary judgment. The decision found that the manner in which the legislature passed the Right of First Refusal law violated the title and single-subject provisions of the Iowa Constitution and therefore held that the law was unconstitutional and unenforceable. The court also granted LS Power's request to enjoin MidAmerican Energy and ITC Midwest from further developing the LRTP Tranche 1 projects, without addressing the federal jurisdictional issues implicated in disrupting MISO's approval of construction of the projects by MidAmerican Energy and ITC Midwest. The court did not rule on the equal protection challenge raised by LS Power and instead held that it was not necessary to reach the merits of those arguments because the title and single-subject violations rendered the statute void and unenforceable. On December 19, 2023, MidAmerican Energy and ITC Midwest filed motions for reconsideration with the Iowa district court that focus on the injunctive relief granted and asked the court to correct legal errors in the order, including over breadth, and to lift the injunction as it relates to the LRTP Tranche 1 projects. To this point, MISO has taken no action to reverse or disrupt its approval of MidAmerican Energy's LRTP Tranche 1 projects. This matter only potentially affects 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 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.

In February 2024, Sierra Pacific filed electric and gas regulatory rate reviews with the PUCN that requested annual revenue increases of $94.7 million, or 8.8% and $11.1 million, or 4.9%, respectively. Orders are expected by the third quarter of 2024 and, if approved, would be effective October 1, 2024.

Northern Powergrid Distribution Companies

Ofgem has completed the five-year RIIO-ED2 price control review that became effective April 1, 2023. The license modifications that gave effect to the price control were published by Ofgem in February 2023. In March 2023, Northern Powergrid sought permission from the Competition and Markets Authority ("CMA") to appeal against those license modifications. The appeal related to two specific areas:

- An error in the method that Ofgem used to allocate price control allowances into the different funding mechanisms resulting in underfunding; and
- Failure by Ofgem to award Northern Powergrid (Yorkshire) plc with a reward under its business plan incentive mechanism.

In September 2023, the CMA found that Ofgem's decision on the allocation of price control allowances was unlawful on the grounds of irrationality and remitted the matter back to Ofgem to redetermine. The CMA found that Ofgem's decision not to grant Northern Powergrid (Yorkshire) plc a reward under its business plan incentive mechanism was valid.

In February 2024, Ofgem published its redetermination on the allocation of Northern Powergrid's price control allowances, resulting in access to £97 million of additional funding for the period April 2023 to March 2028 in 2020/21 prices. This closes Northern Powergrid's appeal.

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 transportation rates by 84% and Zone 2 general system transportation 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 and the outcome of hearing procedures. This matter is pending.

BHE Transmission

AltaLink

2024-2025 General Tariff Application

In April 2023, AltaLink filed its 2024-2025 GTA with the AUC with total transmission tariffs of C$902 million and C$909 million for 2024 and 2025, respectively. The application also requested the approval to reinstate C$99 million cost of removal to rate base which was not previously approved, based on additional information filed.

In July 2023, AltaLink requested the AUC to suspend the schedule for its 2024-2025 GTA until August 31, 2023. AltaLink required the schedule delay to amend its application in response to the unprecedented wildfire events that AltaLink experienced in Alberta, Canada in May and June 2023. In August 2023, AltaLink filed an amendment to its 2024-2025 GTA. The amendment increased AltaLink's Wildfire Mitigation Plan capital expenditures from C$16 million to C$39 million in 2024 and from C$15 million to C$38 million for 2025. AltaLink's total amended transmission tariffs for 2024 and 2025 are C$904 million and C$912 million, respectively.

In December 2023, AltaLink advised the AUC that it reached a negotiated settlement with customer groups on the majority of its 2024-2025 GTA and filed the agreement with the AUC for approval. In February 2024, the AUC issued its decision with respect to AltaLink's 2024-2025 GTA, approving the negotiated settlement agreement as filed. Under the agreement, AltaLink will reduce its applied-for operating expenses by C$7 million and sustaining capital expenditures by C$39 million for the 2024-2025 test period. The agreement does not include AltaLink's proposed wildfire deferral account, certain components of the wildfire mitigation plan, and actual and forecast salvage expenditures from its 2019-2023 GTA and 2024-2025 GTA, respectively. AltaLink's total revised transmission tariffs adjusted for the negotiated settlement are C$900 million for 2024 and C$904 million for 2025. Information responses and AltaLink's rebuttal evidence on the negotiated settlement and the items excluded from the negotiated settlement were provided in February 2024. AltaLink will be adjusting its 2024 transmission tariff and the 8.50% return on equity included in its application filed on December 19, 2023, to the 9.28% return on equity approved by the AUC in the 2024 GCOC proceeding. An oral hearing to address the excluded matters is scheduled in March 2024.

Also, in December 2023, AltaLink filed an application with the AUC to recover all costs incurred as a result of the 2023 spring wildfire and storm events. The application includes capital expenditures of C$18.5 million and salvage expenditures of C$6 million.

In December 2023, the AUC approved 2024 interim refundable transmission tariffs for AltaLink, including monthly tariffs for PLP and KLP, of C$74 million per month effective January 1, 2024.

Generic Cost of Capital Proceeding

In January 2022, the AUC initiated the generic cost of capital proceeding. The proceeding was conducted in two stages. The first stage determined the cost of capital parameters for 2023 and the second stage considered returning to a formula-based approach to establish cost of capital adjustments, commencing in 2024. In March 2022, the AUC issued its decision with respect to the first stage of the generic cost of capital proceeding by approving the extension of the 2022 return on equity of 8.5% and deemed equity ratio of 37% for 2023, recognizing lingering uncertainty and continued volatility of financial markets. In June 2022, the AUC initiated the second stage to explore a formula-based approach to determine the return on equity for 2024 and future test periods.

In February 2023, AltaLink and other stakeholders filed evidence. AltaLink filed expert evidence recommending a 10.3% return on equity, on a recommended equity ratio of 40%. Other utilities filed similar recommendations. The Consumers' Coalition of Alberta, the Utilities Consumer Advocate and the Industrial Power Consumers Association of Alberta recommended returns on equity ranging from 6.75% to 7.7% and equity ratios ranging from 35% to 37%. AltaLink's expert witness, as well as all other utility experts, submitted that they are generally not in favor of implementing a formulaic adjustment mechanism for allowed return on equity due to the challenges in maintaining the Fair Return Standard through formulaic adjustments. The interveners are generally in favor of a formula.

In October 2023, the AUC issued its decision on the Generic Cost of Capital for 2024 and beyond for Alberta's regulated electric and gas utilities, approving an equity ratio and formula to determine return on equity. The AUC set the deemed equity ratio of 37% and the notional return on equity of 9.00%, which is subject to formulaic adjustments utilizing 30-year Government of Canada bond yields and Canadian utility spreads. In November 2023, the AUC issued an order approving 9.28% as the final return on equity for 2024.

BHE U.S. Transmission

A significant portion of ETT's revenues are based on interim rate changes that can be filed twice annually and are subject to review and possible true-up in the next filed base regulatory rate review scheduled for no later than February 1, 2025. In February 2023, the Public Utilities Commission of Texas ("PUCT") approved ETT's request to suspend a base regulatory rate review filing scheduled for February 2023. Results of a base regulatory rate review would be prospective except for any deemed disallowance by the PUCT of the transmission investment since the initial base regulatory rate review in 2007. In June 2018, the PUCT approved ETT's application to reduce its transmission revenue by $28 million to reflect the lower federal income tax rate due to the federal tax rate change from 35% to 21% in 2017, with the amortization of excess accumulated deferred federal income taxes expected to be addressed in the next base rate case.

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 $34.1 billion and (ii) wind tax equity investments of $5.8 billion and has ceased coal operations at 18 coal-fueled generation facilities. As a result, as of December 31 2023, the Company reduced its annual GHG emissions by more than 34% as compared to 2005 levels. The Company plans to continue investing in wind, solar and other low-carbon generation and storage in the future, including (i) $6.9 billion on the construction of renewable generating facilities and repowering certain existing wind-powered generating facilities through 2026 and (ii) $2.0 billion on the construction of electric battery and pumped hydro storage facilities through 2026, and to cease coal operations at an additional 15 coal-fueled generation facilities between 2025 and 2030 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.

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 SO_2, 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 and litigation over Wyoming's SIP was terminated after the effective date of the rule on January 18, 2024. The EPA is also reevaluating 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. Until the EPA takes final action on the proposal and the affected states submit any required SIPs, the relevant Registrants cannot determine the impacts of the proposed rule.

On February 7, 2024, the EPA released final standards for fine particulate matter, PM2.5. The EPA strengthened the primary, health-based annual PM2.5 standard from 12 micrograms per cubic meter to 9 micrograms per cubic meter. The standards were last updated in 2012. Most PM2.5 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.

Cross-State Air Pollution Rule

The EPA promulgated an initial rule in March 2005 to reduce emissions of NO_x and SO_2, 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 SO_2 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. The electric generation sector remains the key industry regulated by the rule and will be subject to emissions allowance trading beginning in summer 2023. 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. Nevada's regional haze SIP has an enforceable retirement date for North Valmy Units 1 and 2 of December 31, 2028, and NV Energy's IRP identified a December 31, 2025, retirement date for the units and is seeking a request of approval from the PUCN to convert the existing coal-fueled generating facility at the North Valmy Generating Station to a cleaner natural gas-fueled generating facility. The EPA's updated modeling suggests that Arizona, Iowa and Kansas may be significantly contributing to nonattainment in downwind states. The EPA intends to undertake additional assessment of its modeling for these states and will determine if it is necessary to address obligations for these states in future actions. The EPA also deferred final action for Wyoming, pending further review of updated air quality and contribution modeling and analysis. 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. Circuit. 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 regional 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. 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 will hear oral arguments on the emergency stay requests February 21, 2024. Until additional rulemaking is completed and litigation is exhausted, the potential impacts to the relevant Registrants cannot be determined.

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. Northern Natural Gas operates 18 affected units; BHE GT&S operates 157 affected units; and Kern River is not affected by the final rule.

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. Relevant to the Registrants, the new state budget for Iowa was determined by optimizing existing post-combustion controls and installation of neural networks. It does not appear that Iowa's revised budget would require additional emissions control equipment because the EPA determined that Iowa contributed to downwind monitor violations only in 2023 (the base year for the Good Neighbor Plan) and not in 2026 (the latest compliance date under the Good Neighbor Plan). However, because the EPA determined that Arizona contributes to monitor violations in both 2023 and 2026, the requirements for that state are more stringent and may drive installation of additional controls. The EPA will accept comment on the supplemental proposal through May 16, 2024. Until the EPA takes final action and litigation is exhausted, the full impacts of the rule cannot be determined.

Regional Haze

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"). Some of PacifiCorp's coal-fueled generating facilities in Utah, Wyoming, Arizona and Colorado and certain of Nevada Power's and Sierra Pacific's fossil-fueled generating facilities are subject to the Clean Air Visibility Rules. In accordance with the federal requirements, states are required to submit SIPs that address emissions from sources subject to BART 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. On January 19, 2021, Heal Utah, National Parks Conservation Association, Sierra Club and Utah Physicians for a Healthy Environment filed a petition for review of the Utah Regional Haze SIP Alternative in the Tenth Circuit. The EPA defended the SIP, and PacifiCorp and the state of Utah intervened in the litigation in support of the EPA. Oral arguments in *HEAL Utah v. EPA* were held March 21, 2023. On August 14, 2023, the Tenth Circuit denied the petition to vacate Utah's first planning period regional haze plan.

The state of Wyoming issued two regional haze SIPs requiring the installation of SO_2, NO_x and particulate matter controls on certain PacifiCorp coal-fueled generating facilities in Wyoming. The EPA approved the SO_2 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 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 must convert Jim Bridger Units 1 and 2 to natural gas and begin meeting emissions limits consistent with that conversion by January 1, 2024. The EPA and PacifiCorp executed an administrative order on consent 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 plan revision replaces a previous requirement for selective catalytic reduction at the units. 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. PacifiCorp remains subject to the compliance terms of the Wyoming consent decree as it works to convert Jim Bridger Units 1 and 2 to natural gas. The EPA is in on-going discussions with Wyoming to finalize a determination on the SIP revisions for Jim Bridger Units 1 and 2, with a decision anticipated by spring 2024.

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 ownership 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 ownership 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.

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 has not yet made determinations on these plans. It was required to make final determinations on the SIPs by August 2023. 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 finding says the agency intends to continue to work with states in developing approvable SIP submittals in a timely manner. The Iowa Department of Natural Resources continues to work with the EPA on development of its SIP. Iowa issued a SIP in August 2023 that requires operational improvements to existing control equipment at MidAmerican Energy Company's Louisa Generation Station and Walter Scott Jr. Energy Center - Unit 3. Iowa submitted that plan to the EPA in fall 2023, where review is pending. 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 in 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. That review is ongoing at the time of filing.

The states of Utah and Wyoming filed deadline suits in the Utah and Wyoming federal district courts in October and November of 2023, asking the court to require 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 has 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 state courts. The EPA is consulting with all groups on appropriate deadlines for agency action on specific state SIPs as the cases move forward in separate courts. As parties in the deadline suits the states and PacifiCorp will be included in settlement discussions and court oversight of the EPA's review of the Utah and Wyoming SIPs. Until the cases are settled and additional rulemaking is completed by the EPA, any potential impacts to the relevant Registrants cannot be determined.

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. Increasingly, states are adopting legislation and regulations to reduce GHG emissions, and local governments and consumers are seeking increasing amounts of clean and renewable energy.

Federal Greenhouse Gas Standards

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 while litigation proceeded. 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 can be taken at a point source facility, specifically heat rate improvements and identified a set of candidate technologies and measures that could improve heat rates. Measures taken to meet the standards of performance must be achieved at the source itself. The Affordable Clean Energy rule was challenged by environmental and health groups in the D.C. Circuit. 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. Arguments in the case were held February 28, 2022, and on June 30, 2022, 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. 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 found that type of regulation, which would impact larger economic forces beyond the fence lines of individual generating facilities, is not permitted under Section 111(d) of the Clean Air Act. 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). The proposed requirements for existing units would take effect January 1, 2030, through state implementation plans. Requirements for new combustion turbines are subcategorized based on capacity factor, where low-load units would be required to meet an emissions limit, intermediate-load units would be required to use a blend of low-emitting hydrogen and natural gas and base-load units would be required to utilize carbon capture and sequestration technology or a high-percentage blend of low-emitting hydrogen. Requirements for existing gas- and oil-fueled steam units are also subcategorized based on capacity factor, where low-load units would be subject to routine maintenance to demonstrate no increase in emissions, intermediate-load units would be subject to an emission limit of 1,500 pounds of CO_2 / MWh-gross and base-load units would be subject to an emission limit of 1,300 pounds of CO_2 / MWh-gross. Control equipment requirements for existing combustion turbines only apply to large, high load turbines that are greater than 300MW in capacity and operate at a greater than 50% capacity factor. These units would be required to begin utilizing carbon capture and sequestration with a 90% capture rate by 2035 or use a blend of low-emitting hydrogen starting in 2032. Requirements for existing coal-fueled units are subcategorized based on retirement date. Units with earlier retirement dates would be subject to less stringent requirements while units that commit to later retirement dates would be subject to annual capacity factor limits or natural gas co-firing requirements. Units that will continue operating after December 31, 2039, would be required to utilize carbon capture and sequestration with a 90% carbon capture rate. Clean Air Act Section 111 establishes a cooperative approach between the EPA and the states. The EPA establishes nationwide standards based on the best system of emissions reductions it identifies for a source category. States are then expected to develop plans to implement those standards at affected units. States may adopt the EPA's standards or develop state-specific standards that achieve the same air quality results. The EPA accepted comments on the proposal through August 8, 2023. In November 2023, the EPA issued a supplement to the proposed rule, seeking comment on impacts to small businesses and whether to include options to address potential reliability issues. The EPA accepted comment on the supplemental proposal through December 20, 2023. The EPA has indicated it intends to finalize the rules by April 2024. The relevant Registrants operate facilities that may be affected by these proposals. Until the EPA takes final action on the proposals, the states submit any required SIPs and litigation is exhausted, the relevant Registrants cannot determine the impacts of the proposed 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 took comment on the proposed rules through January 31, 2022. 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 controls and seals at centrifugal and reciprocating compressors. Additional leak detection and repair surveys and reports are also anticipated. 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 $1500 per metric ton of methane over the 0.11% threshold in 2027. The relevant Registrants do not expect significant impacts from the proposed fee rule due to the combination of the excess emissions threshold, netting allowance and compliance with the methane emissions standards rule. The EPA is accepting comments on the proposed fee rule through March 11, 2024. Until the EPA takes final action on the proposal, the full impacts of the rule cannot be determined.

Water Quality Standards

The Clean Water Act establishes the framework for maintaining and improving water quality in the U.S. through a program that regulates, among other things, discharges to and withdrawals from waterways. The Clean Water Act requires that cooling water intake structures reflect the "best technology available for minimizing adverse environmental impact" to aquatic organisms. After significant litigation, the EPA released a proposed rule under §316(b) of the Clean Water Act to regulate cooling water intakes at existing facilities. The final rule was released in May 2014 and became effective in October 2014. Under the final rule, existing facilities that withdraw at least 25% of their water exclusively for cooling purposes and have a design intake flow of greater than two million gallons per day are required to reduce fish impingement (i.e., when fish and other aquatic organisms are trapped against screens when water is drawn into a facility's cooling system) by choosing one of seven options. Facilities that withdraw at least 125 million gallons of water per day from waters of the U.S. must also conduct studies to help their permitting authority determine what site-specific controls, if any, would be required to reduce entrainment of aquatic organisms (i.e., when organisms are drawn into the facility). PacifiCorp's Dave Johnston generating facility and all of MidAmerican Energy's coal-fueled generating facilities, except Louisa, Ottumwa and Walter Scott, Jr. Unit 4, which have water cooling towers, withdraw more than 125 million gallons per day of water from waters of the U.S. for once-through cooling applications. PacifiCorp's Jim Bridger, Naughton, Gadsby, Hunter and Huntington generating facilities currently utilize closed cycle cooling towers but are designed to withdraw more than two million gallons of water per day. If PacifiCorp's or MidAmerican Energy's existing intake structures require modification, the costs are not anticipated to be significant to the consolidated financial statements. Nevada Power and Sierra Pacific are not impacted by the §316(b) final rule since they do not utilize once-through cooling water intake or discharge structures at any of their generating facilities.

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 March 8, 2023, the EPA proposed 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. However, until the EPA takes final action on the proposal, the full impacts of the rule cannot be determined. The EPA accepted public comments through May 30, 2023, and intends to finalize a rule by spring 2024.

In March 2023, the latest changes to the definition of "waters of the U.S.," a rule that determines which waters are regulated under the federal Clean Water Act, took effect. Under this rule, tributaries, many wetlands, intrastate lakes, intrastate ponds, intrastate streams and some impoundments must meet either test from the 2006 *Rapanos* plurality decision to be considered a water of the U.S. That is, a water must be relatively permanent and have a continuous surface connection to an included waterbody (the "relatively permanent" test) or it must significantly affect the biological, physical or chemical integrity of a traditional navigable water, territorial seas or interstate waters (the "significant nexus" test). The rule was challenged in multiple courts. On May 23, 2023, the U.S. Supreme Court issued a decision in *Sackett v. EPA*, a case that challenged the Clean Water Act's applicability to certain wetlands. In its decision, the U.S. Supreme Court significantly narrowed protections for wetlands and intermittent streams under the federal Clean Water Act. The U.S. Supreme Court unanimously rejected the significant nexus test as unworkable. A divided U.S. Supreme Court determined that jurisdiction applies to waters that are adjacent to traditional interstate navigable waters and that have a continuous surface connection with that traditional interstate navigable waters. In light of the *Sackett* decision, the EPA secured stays of litigation over its definitional rule in two of three pending challenges in order to conduct rulemaking to conform to the U.S. Supreme Court's decision. On September 8, 2023, the EPA issued a new rule conforming to the U.S. Supreme Court's decision.

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 byproducts 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 byproducts 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 byproducts. 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 byproducts 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. At the time the rule was published in April 2015, MidAmerican Energy owned or operated nine surface impoundments and four landfills that contain coal combustion byproducts. 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 byproducts. Five of these surface impoundments were closed on or before December 21, 2017, and the sixth is undergoing closure. 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 byproducts. 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 byproducts 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.

Multiple parties filed challenges over various aspects of the final rule in the D.C. Circuit, resulting in settlement of some of the issues and subsequent regulatory action by the EPA. The EPA finalized the first phase of the CCR rule amendments in July 2018 (the "Phase 1, Part 1 rule"). In addition to adopting alternative performance standards and revising groundwater performance standards for certain constituents, the EPA extended the deadline by which facilities must initiate closure of unlined ash ponds exceeding a groundwater protection standard and impoundments that do not meet the rule's aquifer location restrictions to October 31, 2020. Following submittal of competing motions from environmental groups and the EPA to stay or remand this deadline extension, on March 13, 2019, the D.C. Circuit granted the EPA's request to remand the rule and left the October 31, 2020 deadline in place while the agency undertakes a new rulemaking establishing a new deadline for initiating closure. On August 14, 2019, the EPA released its "Phase 2" proposal, which contains targeted amendments to the CCR rule in response to court remands and EPA settlement agreements, as well as issues raised in a rulemaking petition. The Phase 2 rule has not been finalized. In February 2020, the EPA proposed a federal CCR permit program as required by the WIIN Act of 2016. The federal permit rule has not been finalized. In October 2020, the EPA released an advanced notice of proposed rulemaking on legacy CCR surface impoundments, seeking comment on and information related to issues relevant to development of regulations for legacy impoundments. On May 18, 2023, the EPA proposed the legacy surface impoundments rule and accepted comment on the proposal through July 17, 2023. The proposal encompasses legacy surface impoundments, which are inactive surface impoundments at inactive facilities; and CCR management units ("CCRMU"), which include CCR surface impoundments and landfills that closed prior to October 19, 2015, inactive CCR landfills, and other areas where CCR has been or is managed directly on the land. CCRMUs include all units meeting that definition at active CCR facilities, as well as those at inactive facilities with one or more legacy surface impoundment. EPA proposes the impose substantially the same regulatory obligations for both legacy surface impoundments and CCRMUs as are applicable to currently regulated units, including groundwater monitoring and corrective action. All legacy surface impoundments and CCRMUs would be required to initiate closure, including reclosure, within one year after the rule is finalized. The EPA has indicated it intends to finalize the legacy surface impoundment rule by spring 2024.

The EPA includes lists of potential legacy surface impoundments and CCRMUs in the rulemaking docket and those lists include several BHE facilities. The EPA also specifically identifies PacifiCorp's Huntington Power Plant and NV Energy's Reid Gardner Generating Station as potential CCRMU damage cases based on the EPA's review of compliance information. BHE corrected the record in comments that: (1) The north and south ash ponds at MidAmerican's Riverside Generating Station are incorrectly classified as legacy impoundments rather than CCRMUs; (2) historical impoundments, which were closed according to state requirements and no longer contain CCR or liquids, should be removed from the list of CCRMUs; (3) the EPA erroneously identified NV Energy's Reid Gardner Generating Station and the Old Landfill at PacifiCorp's Huntington generating facility as potential damage cases; and (4) two impoundments at PacifiCorp's former Carbon generating facility are incorrectly included on the list of legacy impoundments because PacifiCorp never managed or disposed of CCR materials in wastewater ponds at the former Carbon generating facility.

The EPA published a Notice of Data Availability on November 14, 2023, in support of its proposed legacy impoundments rule. The notice sought information on two specific pieces of information: (1) an updated list of legacy impoundments and CCRMUs, based on information received during the comment period for the proposed rule; and (2) a risk assessment for legacy impoundments and CCRMUs. The EPA included lists of potential legacy surface impoundments and CCRMUs in the rulemaking docket and those lists included several Berkshire Hathaway Energy facilities. Berkshire Hathaway Energy identified a number of errors and inaccuracies in those lists in comments submitted December 11, 2023.

In August 2020, the EPA finalized its Holistic Approach to Closure: Part A rule ("Part A rule"). This proposal addressed the D.C. Circuit's revocation of the provisions that allow unlined impoundments to continue receiving ash. The Part A rule established a new deadline of April 11, 2021, by which all unlined surface impoundments must initiate closure. The Part A rule also identifies two extensions to that date: (1) a site-specific extension to develop alternate disposal capacity and initiate closure by October 15, 2023; and (2) a site-specific extension for facilities that agree to shut down the coal-fueled unit and complete ash pond closure activities by October 17, 2028. PacifiCorp developed a demonstration for the development of alternative capacity for the Jim Bridger facility's FGD Pond 2 and a demonstration for closure of the Naughton generating facility and ash pond and submitted them to the EPA in November 2020. On January 11, 2022, the EPA deemed these submittals complete but has not taken additional action on them. No other Registrants used the provisions of the Part A rule. On October 12, 2023, Jim Bridger FGD Pond 2 ceased receiving waste and the newly constructed FGD Pond 3 came into service. The EPA was notified on October 12, 2023, of PacifiCorp's withdrawal of its pending Part A alternative storage capacity demonstration request.

Until the 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 byproducts. Some of these cases have been successful in imposing liability upon companies if coal combustion byproducts 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.

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 is a holding company and depends on distributions from subsidiaries, including joint ventures, to meet its obligations.

BHE is a holding company with no material assets other than the ownership interests in its subsidiaries and joint ventures, collectively referred to as its subsidiaries. Accordingly, cash flows and the ability to meet BHE's obligations are largely dependent upon the earnings of its subsidiaries and the payment of such earnings to BHE 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.

BHE's subsidiaries are separate and distinct legal entities and have no obligation, contingent or otherwise, to pay amounts due pursuant to BHE's senior debt, junior subordinated debt or its other obligations, or to make funds available, whether by dividends or other payments, for the payment of amounts due pursuant to BHE's senior debt, junior subordinated debt or its other obligations, and do not guarantee the payment of any of its 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 and preferred stock 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.

BHE is substantially leveraged, the terms of its existing senior and junior subordinated debt do not restrict the incurrence of additional debt by BHE or its subsidiaries, and BHE's senior debt is structurally subordinated to the debt of its subsidiaries, and each of such factors could adversely affect BHE's consolidated 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, 2023, BHE had the following outstanding obligations:

- senior unsecured debt of $13.1 billion;
- junior subordinated debentures of $100 million;
- guarantees and letters of credit in respect of subsidiaries, equity method investments and other related parties aggregating $2.6 billion; and

BHE's consolidated subsidiaries also have significant amounts of outstanding debt, which totaled $41.2 billion as of December 31, 2023. 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 BHE'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. BHE'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 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 senior 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 majority 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 and PacifiCorp's preferred stockholders.

Berkshire Hathaway is majority owner 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 owns 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 owns 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 (the "2020 Wildfires"). 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 (the "2022 McKinney Fire"). Together, the 2020 Wildfires and the 2022 McKinney Fire are referred to as "the Wildfires."

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 Wildfire 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.

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 reserves 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. While certain settlements have occurred, PacifiCorp cannot be certain that additional settlements can be achieved on terms it finds reasonable, if at all.

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, including the implementation of or changes to the Affordable Clean Energy rule, 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. For example, in April 2022, the EPA proposed the "Cross-State Ozone Transport Rule", which contains requirements intended to address ozone transport between states through federally required nitrogen oxide reductions from fossil-fuel generating facilities. The rule included Wyoming, Utah and Nevada for the first time. If finalized as proposed, the rule will have impacts on PacifiCorp's coal-fueled generating facilities in both Utah and Wyoming that do not have an SCR as early as 2026 and threatens early coal-fueled unit retirements and reliability impacts. PacifiCorp has engaged with state and federal agencies to make adjustments to the rule and mitigate potential reliability impacts. 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.

<u>**Operational and Development Risks**</u>

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 with E.ON and British Gas Trading Limited accounting for approximately 19% and 15%, respectively, of distribution revenue in 2023. 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. For example, certain of BHE Renewables' solar and wind independent power projects sell all of their electrical production to either PG&E or SCE, respectively. 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% ownership 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, 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 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.

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 owns 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 (including potentially in relation to COVID-19 variants), 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 its service 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 responsibility for oversight of BHE's cybersecurity risk management program.

BHE's CSO is responsible for cyber and physical security across BHE and its Subsidiary Registrants. The CSO reports directly to the Chief Executive Officer of BHE. The CSO is responsible for identifying, assessing and managing cyber risk for BHE and its Subsidiary Registrants. Management 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 Chief Executive Officer and BHE's Board of Directors on:

- Updates 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

A BHE Cybersecurity Reporting Framework has been adopted so that BHE has 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. BHE's senior management reviews 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 and Notes 4 and 5 of the Notes to Consolidated Financial Statements of Eastern Energy Gas in Item 8 of this Form 10-K.

The following table summarizes Berkshire Hathaway Energy's operating electric generating facilities as of December 31, 2023:

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	12,524	12,524
Natural gas	PacifiCorp, MidAmerican Energy, NV Energy, BHE Canada and BHE Renewables	Nevada, Utah, Iowa, Illinois, Washington, Wyoming, Oregon, Texas, New York, Arizona and Canada	11,250	10,971
Coal	PacifiCorp, MidAmerican Energy and NV Energy	Iowa, Wyoming, Utah, Nevada, Colorado and Montana	12,174	7,483
Solar	MidAmerican Energy, NV Energy, Northern Powergrid and BHE Renewables	California, Australia, Texas, Arizona, Iowa, Minnesota and Nevada	2,120	1,972
Hydroelectric	PacifiCorp, MidAmerican Energy and BHE Renewables	Washington, Oregon, Idaho, Utah, Hawaii, Montana, Illinois, California and Wyoming	985	985
Nuclear	MidAmerican Energy	Illinois	1,809	452
Geothermal	PacifiCorp and BHE Renewables	California and Utah	377	377
		Total	41,239	34,764

Additionally, as of December 31, 2023, the Company has electric generating facilities that are under construction in Nevada, Wyoming and California having total Facility Net Capacity and Net Owned Capacity of 1,284 MWs.

As of December 31, 2023, the Company also has battery energy storage systems in Nevada having total Facility Net Capacity and Net Owned Capacity in operation of 220 MW and under construction of 100 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 2020 Wildfires. Amounts sought in the complaints and demands filed in Oregon and in certain demands made in California total approximately $8 billion, excluding any doubling or trebling of damages included in the complaints and those settled. Generally, the complaints filed in California do not specify damages sought and are excluded from this amount. The complaints and demands filed in Oregon generally seek doubling of economic damages under Oregon law, which provides for such doubling in the event the wildfire is determined to have occurred as a result of recklessness, gross negligence, willfulness or malice. Additionally, those complaints and demands filed in Oregon that involve damages associated with forestry, trees or shrubbery generally seek trebling of damages claimed under Oregon law, which provides for such trebling in the event the damages are determined to have occurred by willful and intentional acts and without consent. Amounts sought for any doubling or trebling of damages are excluded from the amounts described below.

Multiple complaints have also been filed in California for the 2022 McKinney Fire for which the damages sought have not been specified.

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, generally including: (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.

Hitchcock et al. v. PacifiCorp and Consolidated 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 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 California Superior Court, Sacramento County, 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; *Sanchez* complaint filed September 7, 2022, approximately 10 plaintiffs; *Lemon* complaint filed September 2, 2022, approximately 186 plaintiffs; and *Duval* complaint filed September 29, 2022, approximately 24 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 January and February 2024, PacifiCorp reached additional settlements totaling $48 million representing 153 plaintiffs. As a result of the settlements, the *Hitchcock* case set for trial starting March 4, 2024 through March 29, 2024 was cancelled.

Other Slater Fire Cases

On August 17, 2023, a complaint against PacifiCorp was filed captioned *Fernandez et. al v. PacifiCorp*, Case No. 23CV007154 in California Superior Court, Sacramento County, California by approximately 51 plaintiffs. The complaint makes similar allegations as those described above for the Slater Fire and does not specify the amount of damages sought.

On September 8, 2023, a subrogation complaint against PacifiCorp was filed captioned *Travelers Commercial Insurance Company et al. v. PacifiCorp*, Case No. 23CV008226 in California Superior Court, Sacramento County, California by 4 plaintiffs. The complaint makes similar allegations as those described above for the Slater Fire and does not specify the amount of damages sought.

On September 7, 2023, a complaint against PacifiCorp was filed captioned *Thomason et. al v. PacifiCorp*, Case No. 23CV008033 in California Superior Court, Sacramento County, California, by approximately 4 plaintiffs. The complaint makes similar allegations as those described above for the Slater Fire and does not specify the amount of damages sought.

On September 28, 2023, a complaint against PacifiCorp was filed captioned *Bledsoe et. al v. PacifiCorp*, Case No. 23CV009242 in California Superior Court, Sacramento County, California, by three plaintiffs. The complaint makes similar allegations as those described above for the Slater Fire and does not specify the amount of damages sought.

On August 10, 2022, a complaint against PacifiCorp was filed captioned *Siskiyou County v. PacifiCorp*, Case No. 34-2022-00324977 by one plaintiff in California Superior Court, Sacramento County. 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. A jury trial is scheduled for December 2, 2024.

On July 12, 2023, a complaint against PacifiCorp was filed captioned *Susan Irene Terran et. al v. PacifiCorp*, Case No. 23CV27759 in Multnomah County Circuit Court in 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.

Black et al. v. PacifiCorp and Consolidated 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 Oregon Circuit Court in Multnomah County, 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. A jury trial is scheduled for September 23, 2024, through November 1, 2024.

The following complaints filed in Oregon Circuit Court in Multnomah County 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.

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 the U.S. $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) prejudgment 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.

Jeanyne James et al. v. PacifiCorp and Consolidated Cases

On September 30, 2020, a class action complaint against PacifiCorp was filed, captioned *Jeanyne James et al. v. PacifiCorp et al.*, Case No. 20CV33885, in Multnomah County Circuit Court, Oregon ("*James*"). 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.

On April 24, 2023, the jury trial for *James* with respect to the 17 named plaintiffs began in Multnomah County Circuit Court. 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 ordered trial dates for two consolidated jury trials including approximately 10 class members each and a third trial for certain commercial timber plaintiffs wherein plaintiffs in each of the three damages phase trials will present evidence regarding their damages. The first of these trials addressing nine individual plaintiffs was held in January 2024 while the remaining trials are scheduled at various dates through April 2024.

In January 2024, the Multnomah County Circuit Court entered a limited judgment and money award for the June 2023 *James* verdict. The limited judgment awards the aforementioned damages, 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 ORS 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 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. PacifiCorp will request that the Multnomah County Circuit Court judge offset the damage awards by deducting insurance proceeds received by any of the nine plaintiffs. PacifiCorp intends to appeal the jury's damage awards associated with the January 2024 jury verdict once judgement is entered.

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.

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*.

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. A jury trial is scheduled for May 6, 2024, through June 7, 2024.

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. A jury trial is scheduled for May 6, 2024, through June 7, 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.

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. A jury trial is scheduled for April 22, 2024, through April 30, 2024.

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. A jury trial is scheduled for April 22, 2024, through April 30, 2024.

In October 2022, the Multnomah County Circuit Court consolidated *21st Century Centennial Insurance Company, et al. v. PacifiCorp*, Case No. 22CV26326 ("21st Century") and *Allstate Vehicle and Property Insurance Company, et al. v. PacifiCorp*, Case No. 22CV29976 ("Allstate") into *James* (described above). The 21st Century and Allstate complaints were each filed in Multnomah County Circuit Court, Oregon by subrogated insurance carriers resulting from the September 2020 Santiam Canyon, Echo Mountain Complex, 242 and South Obenchain fires. The 21st Century case was filed in August 2022 by 177 insurance carriers seeking not less than $20 million in monetary damages. The Allstate case was filed in September 2022 by 11 insurance carriers seeking not less than $40 million in monetary damages. In April 2023, PacifiCorp and the subrogated insurance carriers entered into a settlement agreement. In September 2023, PacifiCorp paid $55 million in settlements associated with the subrogation claims. As a result of the settlement, the *21st Century* and *Allstate* cases have been dismissed.

Roseburg Resources Co et al. v. PacifiCorp and Consolidated Cases (Archie Creek Fire)

On March 17, 2022, a complaint against PacifiCorp was filed, captioned *Roseburg Resources Co et al. v. PacifiCorp*, Case No. 22CV09346 ("*Roseburg*") in Douglas County Circuit Court, Oregon. The complaint was filed by nine businesses and public pension plans that own or operate timberlands or possess property in Douglas County who allege damages, losses and injuries associated with their timberlands as a result of the French Creek, Archie Creek, Susan Creek and Smith Springs Road fires in Douglas County in September 2020. The complaint was amended in September 2023 and seeks economic damages of $195 million; attorney's fees, experts fees and other costs of $105 million; and pre-judgment interest of $43 million.

The following complaints were filed in Douglas County Circuit Court, Oregon with substantially similar allegations as those of Roseburg with the exception that certain of the complaints do not allege inverse condemnation. On February 9, 2023, in an oral ruling, the Douglas County Circuit Court ordered these seventeen cases consolidated for trial as to certain specified issues, along with the above-mentioned *Roseburg* case; the precise scope of the trial will be determined in a later order. Collectively, these eighteen cases seek economic damages of $531 million and noneconomic damages of $102 million, inclusive of the $195 million of economic damages in the *Roseburg* case. *Moore* filed November 1, 2022, approximately 8 plaintiffs; *Blodgett* filed November 1, 2022, approximately 11 plaintiffs; *Ellis* filed November 1, 2022, approximately 10 plaintiffs; *Tague* filed December 5, 2022, approximately 28 plaintiffs; *Long* filed December 5, 2022, approximately 33 plaintiffs; *Moyers* filed December 5, 2022, approximately 41 plaintiffs; *Meyer* filed January 6, 2023, approximately 11 plaintiffs; *Foster* filed January 17, 2023, approximately 44 plaintiffs; *Hall* filed January 17, 2023, approximately 39 plaintiffs; *Jones* filed January 17, 2023, approximately 47 plaintiffs; *Price* filed January 17, 2023, approximately 39 plaintiffs; *Minott* filed January 17, 2023, approximately 33 plaintiffs; *Webb* filed January 17, 2023, approximately 30 plaintiffs; *Keith* filed January 17, 2023, approximately 40 plaintiffs; *Kidd* filed January 24, 2023, approximately 12 plaintiffs; *Parker* filed January 24, 2023, approximately 16 plaintiffs; and *Diaz* filed January 24, 2023, approximately 14 plaintiffs.

On February 14, 2023, the Douglas County Circuit Court ordered that all plaintiffs' claims for inverse condemnation be dismissed.

In December 2023, PacifiCorp entered into settlement agreements with 463 claimants and 10 companies with commercial timber interests associated with the Archie Creek Fire generally associated with the consolidated *Roseburg* cases and paid $299 million to the 463 claimants and $250 million to the 10 companies with commercial timber interests. These settlements resolve substantially all claims filed by individual plaintiffs and all claims filed by commercial timber plaintiffs associated with the consolidated *Roseburg* cases and claims filed by certain of the plaintiffs associated with the *Beamer* case described below, but do not address related damages claimed by the U.S. or Oregon Departments of Justice also described below. As a result of the settlement, only the *Lee*, *Beamer* and insurance subrogation cases remain active; the *Roseburg* consolidated cases have been dismissed.

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 in Oregon Circuit Court in Multnomah County, Oregon by approximately five plaintiffs, seeking approximately $63 million in economic damages and $63 million in noneconomic damages and makes allegations similar to those described above.

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 in Oregon Circuit Court in Douglas County, 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. As a result of the December 2023 settlement described above, claims associated with approximately 27 plaintiffs in the *Beamer* case were resolved.

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 Oregon Circuit Court in Douglas County, Oregon seeking $14 million in damages for negligence associated with the Archie Creek Fire and, as amended on February 3, 2022, make 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 Oregon Circuit Court in Douglas County, 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 remains pending because general judgment of dismissal has not yet been entered because certain plaintiffs remain active.
>
> The *Ace American Insurance Co.* complaint was filed against PacifiCorp in Oregon Circuit Court in Douglas County, 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.

Ashley Andersen et al. v. PacifiCorp and Consolidated Cases

On November 16, 2021, a complaint against PacifiCorp was filed in Multnomah County Circuit Court, Oregon, captioned *Ashley Andersen et al. v. PacifiCorp,* Case No. 21CV36567 ("*Andersen*"). 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 fires. 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* 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: *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; *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.

The *Andersen* case is set for trial starting August 19, 2024, through September 13, 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. A jury trial is scheduled for November 4, 2024, through November 29, 2024.

The following cases also associated with the Beachie Creek Fire have been 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.

Other Cases

On October 7, 2021, a complaint against PacifiCorp was filed captioned *Estate of Cathy Lynn Cook et. al v. PacifiCorp,* Case No. 21CV35076 ("*Cook*") in Oregon Circuit Court in Multnomah County, Oregon, approximately two plaintiffs, seeking a minor amount of economic damages and approximately $40 million in noneconomic damages associated with the Beachie Creek Fire, 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. The *Cook* case is set for trial starting July 5, 2024, through July 19, 2024.

On October 7, 2021, a complaint against PacifiCorp was filed captioned *Angela Mosso et. al v. PacifiCorp,* Case No. 21CV35069 in Oregon Circuit Court in Multnomah County, Oregon, approximately four plaintiffs, seeking approximately $10 million in economic damages and $90 million in noneconomic damages associated with the Beachie Creek Fire, 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. The *Mosso* case is set for trial starting August 5, 2024, through August 16, 2024.

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

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.

On January 18, 2024, a complaint against PacifiCorp was filed captioned *Sokol Blosser, Ltd. et. al v. PacifiCorp*, Case No. 24CV03044 in Oregon Circuit Court in Multnomah County, Oregon, approximately nine plaintiffs, seeking approximately $20 million in economic damages associated with multiple fires and makes allegations similar to those described above.

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, one plaintiff, seeking approximately $3 million in economic damages associated with multiple fires and makes allegations similar to those described above.

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, approximately four plaintiffs, seeking approximately $4 million in economic damages associated with multiple fires and makes allegations similar to those described above.

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.

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 September 1, 2022, a complaint against PacifiCorp was filed captioned *Stroh Coastal Holdings LLC, v. PacifiCorp*, Case No. 22CV29695 in Oregon Circuit Court in Multnomah County, Oregon, one plaintiff, seeking $1 million in economic damages associated with the Pike Road Fire and makes allegations similar to those described above.

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

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

PacifiCorp received correspondence from the USDOJ, representing the U.S. Department of the Interior, Bureau of Land Management, Bureau of Indian Affairs, Department of Agriculture and Forest Service, 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 estimates for mediation purposes only the costs and damages relating to reforestation, damaged timber and improvements, coordination with hydropower license, suppression costs and other assessment, cleanup and rehabilitation costs and damages at approximately $625 million. 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.

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 estimates for mediation purposes only losses and damages relating to the sheltering of, and assistance to, affected Oregonians, fire control and extinguishment costs, 39 acres of Oregon forestland, losses and damages at the Rock Creek Fish Hatchery, road and highway damages, and other costs, at approximately $109 million.

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.

PacifiCorp is actively cooperating with both the USDOJ and ODOJ on resolving these alleged claims, including through the pursuit of alternative dispute resolution.

2022 McKinney Fire

Numerous complaints associated with the 2022 McKinney Fire have been filed in California Superior Court, Sacramento County, 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, as well as, in limited cases, wrongful death claims. 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, in California Superior Court, Sacramento County, California ("*Bridges*") by approximately five 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 180 plaintiffs; *Muelrath* filed January 18, 2023, approximately two plaintiffs; *California Fair Plan Association*, filed March 3, 2023, approximately 18 subrogation insurers; *Corrales*, filed April 6, 2023, approximately 30 plaintiffs; *Murieen*, filed April 20, 2023, approximately seven plaintiffs; *Hickey*, filed May 9, 2023, approximately five plaintiffs; and *Volckhausen*, filed May 9, 2023, one plaintiff; *Huber*, filed August 21, 2023, approximately three plaintiffs, including a wrongful death claim; *CSAA* filed December 21, 2023, one subrogation insurer.

In November 2023, PacifiCorp settled the *Muelrath* claims and the trial date was vacated.

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 ("*Siskiyou County*") on behalf of a single plaintiff. A jury trial is scheduled for September 22, 2025.

On January 8, 2024, a complaint against PacifiCorp was filed, captioned *Insurance Company of Hannover v. PacifiCorp*, Case No. 24CV000183, in Sacramento Superior Court, California, by one subrogation plaintiff.

BERKSHIRE HATHAWAY ENERGY

HomeServices, a subsidiary of Berkshire Hathaway Energy, is currently defending against eleven antitrust cases, all in federal district courts. In each case, plaintiffs claim HomeServices (or, in one instance, Berkshire Hathaway) and certain of its subsidiaries 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 provided written notice of the damages sought totaling approximately $9 billion by separate notice as required by Texas law. The cases are captioned as follows.

In April 2019, the *Burnett (formerly Sitzer) 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 Sitzer and Amy Winger against the National Association of Realtors ("NAR"), Anywhere Real Estate (formerly Realogy Holdings Corp.), 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 (formerly Realogy Holdings Corp.) and RE/MAX, LLC reached settlement agreements with the plaintiffs, which have not yet been approved by the court. Final judgment has not yet been entered by the U.S. District Court for the Western District of Missouri. 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 (formerly Realogy Holdings Corp.), 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 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 (formerly Realogy Holdings Corp.), 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.

In January 2021, the *Batton (formerly Leeder) v. HomeServices of America, Inc. et al.*, Case No. 21CV00430, complaint was filed in the U.S. District Court for the Northern District of Illinois. This putative class action lawsuit was originally brought on behalf of former named plaintiff Judah Leeder against the NAR, HomeServices of America, Inc. HSF Affiliates, LLC, BHH Affiliates, LLC, Long & Foster Companies, Inc. (also a HomeServices subsidiary), Anywhere Real Estate (formerly Realogy Holdings Corp.), RE/MAX, LLC and Keller Williams Realty, Inc. Mya Batton replaced Leeder as class representative in July 2022. This case has been brought on behalf of a putative class of real estate buyers; all other referenced cases have been brought on behalf of real estate sellers. On February 20, 2024, the court entered an order dismissing HomeServices of America, Inc., HSF Affiliates, LLC, BHH Affiliates, LLC and Long & Foster Companies, Inc. from the case without prejudice.

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 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 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 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 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 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 February 2024, the *Jensen v. HomeServices of America, Inc., et al.*, Case No. 24CV00109, complaint was filed in the U.S. District Court for the District of Utah. The putative class action lawsuit was brought on behalf of named plaintiff Dalton Jensen against the NAR, Anywhere Real Estate, Inc., HomeServices of America, Inc., HSF Affiliates, LLC, BHH Affiliates, LLC and additional named defendants.

In February 2024, the *Boykin v. BHH Affiliates, LLC, et al.*, Case No. 24CV00340, compliant 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.

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 beneficially owned by Berkshire Hathaway and family members and related or affiliated entities of the late Mr. Walter Scott, Jr., a former member of BHE's Board of Directors, 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 ownership 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 $300 million in 2023, $100 million in 2022 and $150 million in 2021.

MIDAMERICAN FUNDING AND MIDAMERICAN ENERGY

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 is an Iowa limited liability company whose membership interest is held solely by BHE. MidAmerican Funding declared and paid cash distributions to BHE of $425 million in 2024, $1,025 million in 2023, $69 million in 2022 and $— million in 2021. MidAmerican Energy declared and paid cash dividends to MHC totaling $425 million in 2024, $1,025 million in 2023, $275 million in 2022 and $— million in 2021.

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 $50 million in 2023, $— million in 2022 and $213 million in 2021.

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 $150 million in 2024, $100 million in 2023, $70 million in 2022 and $— million in 2021.

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 $332 million in 2023, $— million in 2022 and $— million in 2021.

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 $158 million in 2023, $215 million million in 2022 and $18 million in 2021.

Item 6. [Reserved]

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

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Item 8. Financial Statements and Supplementary Data

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. Effective January 1, 2023, the Company's unregulated retail energy services business was transferred to a subsidiary of BHE Renewables. Prior period amounts, which were previously reported in BHE and Other, have been reclassified to reflect this activity in BHE Renewables.

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):

	2023	2022	Change		2022	2021	Change	
Operating revenue:								
PacifiCorp	$ 5,936	$ 5,679	$ 257	5 %	$ 5,679	$ 5,296	$ 383	7 %
MidAmerican Funding	3,393	4,025	(632)	(16)	4,025	3,547	478	13
NV Energy	4,523	3,824	699	18	3,824	3,107	717	23
Northern Powergrid	1,303	1,365	(62)	(5)	1,365	1,188	177	15
BHE Pipeline Group	3,774	3,844	(70)	(2)	3,844	3,544	300	8
BHE Transmission	799	732	67	9	732	731	1	—
BHE Renewables	1,710	1,737	(27)	(2)	1,737	1,661	76	5
HomeServices	4,322	5,268	(946)	(18)	5,268	6,215	(947)	(15)
BHE and Other	(158)	(137)	(21)	15	(137)	(139)	2	(1)
Total operating revenue	$25,602	$26,337	$ (735)	(3)%	$26,337	$25,150	$ 1,187	5 %
Earnings on common shares:								
PacifiCorp	$ (468)	$ 921	$ (1,389)	(151)%	$ 921	$ 889	$ 32	4 %
MidAmerican Funding	980	947	33	3	947	883	64	7
NV Energy	394	427	(33)	(8)	427	439	(12)	(3)
Northern Powergrid	165	385	(220)	(57)	385	247	138	56
BHE Pipeline Group	1,079	1,040	39	4	1,040	807	233	29
BHE Transmission	246	247	(1)	—	247	247	—	—
BHE Renewables(1)	518	643	(125)	(19)	643	459	184	40
HomeServices	13	100	(87)	(87)	100	387	(287)	(74)
BHE and Other	59	(2,035)	2,094	*	(2,035)	1,311	(3,346)	*
Total earnings on common shares	$ 2,986	$ 2,675	$ 311	12 %	$ 2,675	$ 5,669	$ (2,994)	(53)%

(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 $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 Company Limited ("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 CE Gas, higher deferred income tax expense, including amounts related to the enactment of a new Energy Profits Levy income tax at the CE Gas business, and increased non-service benefit plan costs. Units distributed declined 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 DEI's 50% limited partner interests 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 wind tax equity investments, 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 the $2,045 million favorable comparative change in fair value related to the Company's investment in BYD.

Earnings on common shares decreased $2,994 million for 2022 compared to 2021. Included in these results was a pre-tax loss in 2022 of $1,950 million ($1,540 million after-tax) compared to a pre-tax gain in 2021 of $1,796 million ($1,777 million after-tax) related to the Company's investment in BYD. Excluding the impact of this item, adjusted earnings on common shares in 2022 was $4,215 million, an increase of $323 million, or 8%, compared to adjusted earnings on common shares in 2021 of $3,892 million.

The decrease in earnings on common shares for 2022 compared to 2021 was primarily due to:

- The Utilities' earnings increased $84 million reflecting higher electric utility margin and higher PTCs recognized of $157 million, partially offset by higher operations and maintenance expense and higher depreciation and amortization expense. Electric retail customer volumes increased 2.4% for 2022 compared to 2021, primarily due to higher customer usage, an increase in the average number of customers and the favorable impact of weather;
- Northern Powergrid's earnings increased $138 million, primarily due to a deferred income tax charge of $109 million related to a June 2021 enacted increase in the United Kingdom corporate income tax rate from 19% to 25% effective April 1, 2023 and favorable earnings from new gas and solar projects, partially offset by $41 million from the stronger U.S. dollar;
- BHE Pipeline Group's earnings increased $233 million due to higher earnings at BHE GT&S from the impacts of the EGTS general rate case, favorable income tax adjustments, lower operations and maintenance expense and higher margin from non-regulated activities;
- BHE Renewables' earnings increased $184 million, primarily due to higher operating revenue from owned renewable energy projects and higher earnings from wind tax equity investments, mainly due to the unfavorable impacts from the February 2021 polar vortex weather event;

- HomeServices' earnings decreased $287 million, reflecting lower earnings from brokerage and settlement services largely attributable to a decrease in closed units at existing companies and lower earnings from mortgage services mainly from a decrease in funded volumes; and
- BHE and Other's earnings decreased $3,346 million, primarily due to the $3,317 million unfavorable comparative change in fair value related to the Company's investment in BYD.

Reportable Segment Results

PacifiCorp

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 an increase in 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, unfavorable 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 power 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.

Operating revenue increased $383 million for 2022 compared to 2021, primarily due to higher retail revenue of $263 million, and higher wholesale and other revenue of $120 million, largely from higher average wholesale prices. Retail revenue increased primarily due to price impacts of $166 million from higher average rates largely due to sales mix and tariff changes and $97 million from higher retail volumes. Retail customer volumes increased 1.6%, primarily due to the favorable impact of weather and an increase in the average number of customers, partially offset by lower customer usage.

Earnings increased $32 million for 2022 compared to 2021, primarily due to higher utility margin of $235 million and higher allowances for equity and borrowed funds used during construction of $28 million, partially offset by higher operations and maintenance expense of $196 million, higher depreciation and amortization expense of $32 million, mainly from additional assets placed in-service, unfavorable changes in the cash surrender value of corporate-owned life insurance policies and an unfavorable income tax benefit. Utility margin increased primarily due to favorable deferred net power costs, higher retail rates and volumes and higher average wholesale prices, partially offset by higher purchased power and thermal generation costs. Operations and maintenance expense increased mainly due to an increase in wildfire loss accruals, net of expected insurance recoveries of $64 million and higher general and plant maintenance costs. The unfavorable income tax benefit was largely due to state income tax impacts, partially offset by higher PTCs recognized of $21 million.

MidAmerican Funding

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 a lower average per-unit cost of natural gas sold resulting in lower purchased gas adjustment recoveries of $311 million (fully offset in cost of sales) and the unfavorable impact of weather of $19 million, partially offset by higher average 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 expense, primarily cost of sales), 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.

Operating revenue increased $478 million for 2022 compared to 2021, primarily due to higher electric operating revenue of $459 million and higher natural gas operating revenue of $27 million. Electric operating revenue increased due to higher wholesale and other revenue of $261 million and higher retail revenue of $198 million. Electric wholesale and other revenue increased mainly due to higher average wholesale prices of $229 million and higher wholesale volumes of $36 million. Electric retail revenue increased primarily due to higher recoveries through adjustment clauses of $134 million (fully offset in expense, primarily cost of sales) and higher customer volumes of $62 million. Electric retail customer volumes increased 4.3%, primarily due to higher customer usage and the favorable impact of weather. Natural gas operating revenue increased due to higher customer usage of $9 million, the favorable impact of weather of $9 million and the impacts of tax reform of $5 million.

Earnings increased $64 million for 2022 compared to 2021, primarily due to higher electric utility margin of $319 million, a favorable income tax benefit and higher natural gas utility margin of $25 million, partially offset by higher depreciation and amortization expense of $254 million, higher operations and maintenance expense of $53 million, unfavorable changes in the cash surrender value of corporate-owned life insurance policies and higher non-service benefit plan costs of $17 million. Electric utility margin increased primarily due to higher wholesale and retail revenues, partially offset by higher purchased power and thermal generation costs. The favorable income tax benefit was mainly due to higher PTCs recognized of $136 million, partially offset by state income tax impacts. Depreciation and amortization expense increased primarily from the impacts of certain regulatory mechanisms and additional assets placed in-service. Operations and maintenance expense increased due to higher general and plant maintenance costs.

NV Energy

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 average per-unit cost of natural gas sold (fully offset in cost of sales). Electric operating revenue increased primarily due to higher fully bundled energy rates (fully offset in cost of sales) of $649 million and increased base tariff general 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 tariff general rates at Sierra Pacific.

Operating revenue increased $717 million for 2022 compared to 2021, primarily due to higher electric operating revenue of $668 million and higher natural gas operating revenue of $51 million from a higher average per-unit cost of natural gas sold (fully offset in cost of sales). Electric operating revenue increased primarily due to higher fully-bundled energy rates (fully offset in cost of sales) of $636 million, higher regulatory-related revenue deferrals of $15 million and higher customer volumes of $6 million. Electric retail customer volumes increased 2.2%, primarily due to an increase in the average number of customers, partially offset by the unfavorable impact of weather.

Earnings decreased $12 million for 2022 compared to 2021, primarily due to higher operations and maintenance expense of $24 million, higher depreciation and amortization expense of $17 million, higher interest expense of $15 million, unfavorable changes in the cash surrender value of corporate-owned life insurance policies and higher non-service benefit plan costs of $11 million, partially offset by higher interest and dividend income of $36 million from carrying charges on regulatory balances and higher electric utility margin of $32 million. Operations and maintenance expense increased mainly due to higher general and plant maintenance costs and an unfavorable change in earnings sharing at the Nevada Utilities. Depreciation and amortization expense increased mainly from additional assets placed in-service. Electric utility margin increased mainly due to higher regulatory-related revenue deferrals of $15 million and higher electric retail customer volumes.

Northern Powergrid

Operating revenue decreased $62 million for 2023 compared to 2022, primarily due to lower revenue at CE Gas of $48 million and lower distribution revenue of $48 million, partially offset by higher non-regulated contracting revenue of $18 million and $11 million from the weaker U.S. dollar. CE Gas revenue decreased due to lower gas production volumes and prices from a gas project that commenced commercial operations in March 2022, partially offset by a solar project that commenced commercial operations in July 2022. 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 3.3% decline 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 gas exploration costs of $92 million, unfavorable operating performance at CE Gas of $61 million, higher deferred income tax expense, including amounts related to the enactment of a new Energy Profits Levy income tax at the CE Gas business, increased non-service benefit plan costs of $35 million and higher distribution-related operating and depreciation expenses of $18 million, partially offset by lower interest expense of $14 million. The unfavorable operating performance at CE Gas was largely due to lower gas production volumes and prices from a gas project that commenced commercial operations in March 2022, partially offset by a solar project that commenced commercial operations in July 2022.

Operating revenue increased $177 million for 2022 compared to 2021, primarily due to higher distribution revenue of $167 million and higher revenue at CE Gas of $158 million, due to a gas project that commenced commercial operation in March 2022 and a solar project that commenced commercial operation in July 2022, partially offset by $155 million from the stronger U.S. dollar. Distribution revenue increased primarily due to the recovery of Supplier of Last Resort payments of $135 million (largely offset in cost of sales) and higher tariff rates of $78 million, partially offset by a 4.6% decline in units distributed of $36 million.

Earnings increased $138 million for 2022 compared to 2021, primarily due to a deferred income tax charge of $109 million related to a June 2021 enacted increase in the United Kingdom corporate income tax rate from 19% to 25% effective April 1, 2023, higher distribution tariff rates and improved earnings of $47 million from the new gas and solar projects, partially offset by $41 million from the stronger U.S. dollar, lower units distributed and higher distribution-related operating and depreciation expenses of $25 million.

BHE Pipeline Group

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 transportation revenue 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 (largely offset in cost of sales) 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 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 DEI's 50% limited partner interests 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 compensation costs and higher technology and related charges.

Operating revenue increased $300 million for 2022 compared to 2021, primarily due to higher operating revenue of $242 million at BHE GT&S and $47 million at Northern Natural Gas. The increase in operating revenue at BHE GT&S was primarily due to higher non-regulated revenue of $109 million (largely offset in cost of sales) from favorable commodity prices, an increase in regulated gas transportation and storage services rates due to the settlement of EGTS' general rate case of $101 million and higher LNG revenue of $56 million at Cove Point, largely from favorable variable revenue, partially offset by lower gas sales of $49 million at EGTS from system balancing activities. The increase in operating revenue at Northern Natural Gas was mainly due to higher transportation revenue of $63 million offset by lower gas sales of $14 million from system balancing activities. The variances in transportation revenue and gas sales included favorable impacts recognized of $49 million and $77 million, respectively, from the February 2021 polar vortex weather event. Excluding this item, transportation revenue increased $112 million due to higher volumes and rates and gas sales increased $63 million (largely offset in cost of sales).

Earnings increased $233 million for 2022 compared to 2021, primarily due to higher earnings of $232 million at BHE GT&S. Earnings at BHE GT&S increased mainly due to the impacts of the EGTS general rate case of $124 million, favorable income tax adjustments, lower operations and maintenance costs and a decrease in property and other tax expense of $30 million, higher margin of $26 million from non-regulated activities and increased earnings at Cove Point of $16 million.

BHE Transmission

Operating revenue increased $67 million for 2023 compared to 2022, primarily due to $69 million of incremental revenue from non-regulated wind-powered generating facilities acquired in November 2022 and higher other non-regulated revenue at BHE Canada, 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 the higher non-regulated revenue at BHE Canada.

Operating revenue increased $1 million for 2022 compared to 2021, primarily due to higher non-regulated revenue from wind-powered generating facilities, partially offset by $27 million from the stronger U.S. dollar.

Earnings for 2022 were equal to 2021, primarily due to improved equity earnings from ETT offset by $7 million from the stronger U.S. dollar.

BHE Renewables

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 wind tax equity investments 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.

Operating revenue increased $76 million for 2022 compared to 2021, primarily due to higher wind, geothermal, and solar revenues of $140 million from higher generation and pricing, and higher natural gas and electric retail energy services revenue of $64 million due to favorable electric volumes and natural gas pricing, including changes in unrealized positions on derivative contracts, offset by lower electric pricing and natural gas volumes. These items were partially offset by lower natural gas revenues of $72 million from lower generation and pricing, lower hydro revenues of $28 million due to the transfer of the Casecnan generating facility to the Philippine government in December 2021 and $27 million from unfavorable changes in the valuation of certain derivative contracts.

Earnings increased $184 million for 2022 compared to 2021, primarily due to higher wind earnings of $214 million, higher geothermal earnings of $16 million and higher solar earnings of $14 million, partially offset by lower natural gas earnings of $44 million and lower hydro earnings of $18 million due to the Casecnan generating facility transfer. Wind earnings increased due to higher earnings from tax equity investments of $153 million, largely as a result of the unfavorable impacts recognized in 2021 from the February 2021 polar vortex weather event and higher production tax credits, and higher earnings from owned projects of $61 million.

HomeServices

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.

Operating revenue decreased $947 million for 2022 compared to 2021, primarily due to lower brokerage and settlement services revenue of $637 million and lower mortgage revenue of $305 million. The decrease in brokerage and settlement services revenue resulted from an 11% decrease in closed transaction volume driven by 23% fewer closed units at existing companies resulting from rising interest rates and a corresponding slowdown in home sales offset by acquisitions and a 7% increase in average sales price. The lower mortgage revenue was due to a 40% decrease in funded volume, primarily due to a decline in refinance activity resulting from rising interest rates.

Earnings decreased $287 million for 2022 compared to 2021, primarily due to lower earnings from brokerage and settlement services of $142 million and mortgage services of $126 million, largely from declines in closed brokerage transaction volume and mortgage funded volume. Earnings at brokerage and settlement services declined due to the decrease in closed units at existing companies, partially offset by favorable operating expense variances.

BHE and Other

Earnings increased $2,094 million for 2023 compared to 2022, primarily due to the Company's investment in BYD including the $2,045 million favorable comparative change in fair value, 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.

Earnings decreased $3,346 million for 2022 compared to 2021, primarily due to the Company's investment in BYD, including the $3,317 million unfavorable comparative change in fair value, lower consolidated state income tax benefits, higher BHE corporate interest expense from an April 2022 debt issuance and unfavorable changes in the cash surrender value of corporate-owned life insurance policies, partially offset by $75 million of lower dividends on BHE's 4.00% Perpetual Preferred Stock issued to certain subsidiaries of Berkshire Hathaway and lower corporate costs.

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, 2023, 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	$ 166	$ 138	$ 637	$ 58	$ 44	$ 66	$ 280	$ 176	$ 1,565
Credit facilities[(1)]	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	1,565	147	1,203	1,000	254	752	1,080	—	6,001
Total net liquidity[(2)]	$1,731	$ 285	$ 1,840	$1,058	$ 298	$ 818	$ 1,360	$ 176	$ 7,566
Credit facilities:									
Maturity dates	2026	2026	2024, 2026	2026	2026	2024, 2026, 2027, 2028	2024		

(1) Includes $92 million drawn on capital expenditure and other uncommitted credit facilities at Northern Powergrid.

(2) Excludes $900 million of available liquidity under a delayed draw term loan at PacifiCorp and $700 million from a credit facility at HomeServices that is unavailable due to borrowing restrictions pursuant to the credit agreement.

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, 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.

Net cash flows from operating activities for the years ended December 31, 2022 and 2021 were $9.4 billion and $8.7 billion, respectively. The increase was primarily due to an increase in income tax receipts and improved operating results, partially offset by changes in regulatory assets and 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, 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.

Net cash flows from investing activities for the years ended December 31, 2022 and 2021 were $(7.8) billion and $(5.8) billion, respectively. The change was primarily due to the July 2021 receipt of $1.3 billion due to the termination of the second Purchase and Sale Agreement with Dominion Energy Questar Corporation, higher capital expenditures of $894 million and higher cash paid for acquisitions, partially offset by lower funding of tax equity investments. 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, 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, purchases 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.

Net cash flows from financing activities for the year ended December 31, 2021 were $(3.1) billion. Sources of cash totaled $2.4 billion and consisted of proceeds from subsidiary debt issuances. Uses of cash totaled $5.5 billion and consisted mainly of preferred stock redemptions totaling $2.1 billion, repayments of subsidiary debt totaling $2.0 billion, distributions to noncontrolling interests of $488 million, repayments of BHE senior debt totaling $450 million and net repayments of short-term debt totaling $276 million.

Recent Financing Transactions

In January and February 2024, the Company issued $5.1 billion of term debt with a weighted average interest rate of 5.4% and maturity dates ranging from 2029 to 2055 and repaid short term borrowings of approximately $2.8 billion.

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, 2022 and 2021, BHE redeemed at par 849,982, 800,006 and 2,100,012 shares of its 4.00% Perpetual Preferred Stock from certain subsidiaries of Berkshire Hathaway Inc. for $850 million, $800 million and $2.1 billion.

Common Stock Transactions

For the year ended December 31, 2022, BHE purchased 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.

There were no common stock repurchases for the years ended December 31, 2023 and 2021.

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		
	2021	**2022**	**2023**	**2024**	**2025**	**2026**
PacifiCorp	$ 1,513	$ 2,166	$ 3,226	$ 3,577	$ 3,545	$ 3,492
MidAmerican Funding	1,912	1,869	1,833	1,880	2,761	2,792
NV Energy	749	1,113	1,797	1,840	2,200	2,945
Northern Powergrid	742	768	557	872	978	997
BHE Pipeline Group	1,128	1,157	1,294	1,177	1,241	1,038
BHE Transmission	279	200	206	330	441	447
BHE Renewables	227	140	177	638	197	193
HomeServices	42	48	41	40	43	41
BHE and Other[1]	19	44	17	24	12	20
Total	$ 6,611	$ 7,505	$ 9,148	$ 10,378	$ 11,418	$ 11,965

(1) BHE and Other includes intersegment eliminations.

	Historical			Forecast		
	2021	2022	2023	2024	2025	2026
Electric transmission	$ 799	$ 1,693	$ 1,802	$ 2,121	$ 2,445	$ 2,804
Electric distribution	1,620	1,650	2,047	2,293	2,528	2,243
Wind generation	1,339	774	1,538	1,317	1,909	1,798
Natural gas transmission and storage	1,068	945	997	924	1,014	952
Electric battery and pumped hydro storage	23	16	371	350	572	1,103
Solar generation	157	422	271	224	584	1,067
Wildfire mitigation	83	188	352	409	364	368
Other	1,522	1,817	1,770	2,740	2,002	1,630
Total	$ 6,611	$ 7,505	$ 9,148	$ 10,378	$ 11,418	$ 11,965

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 planned costs for the following major transmission segments: the 416-mile, 500-kV high-voltage transmission line between the Aeolus substation near Medicine Bow, Wyoming and the Clover substation near Mona, Utah; the 59-mile, 230-kV high-voltage transmission line between the Windstar substation near Glenrock, Wyoming and the Aeolus substation; the 290-mile, 500-kV high-voltage transmission line from the Longhorn substation near Boardman, Oregon to the Hemingway substation near Boise, Idaho; the 14-mile, 345-kV high-voltage transmission line between the Oquirrh substation in the Salt Lake Valley and the Terminal substation near the Salt Lake City Airport; and the 200-mile, 500-kV high-voltage transmission line between the Anticline substation near Point of Rocks, Wyoming and the Populus substation in Downey, Idaho. Planned spending for major transmission segments that are expected to be placed in-service in 2024 through 2031 totals $694 million in 2024, $325 million in 2025 and $504 million in 2026.
    - Nevada Utilities' Greenlink Nevada transmission expansion program. The Nevada Utilities have received approval from the PUCN to build 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 Robinson Summit substation, near Ely, Nevada. Planned spending for the expansion program estimated to be placed in-service in 2027 through 2028 totals $281 million in 2024, $584 million in 2025 and $713 million in 2026.
    - 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 $608 million for 2023, $72 million for 2022 and $540 million for 2021. MidAmerican Energy placed in-service 200 MWs during 2023 and 294 MWs during 2021. Planned spending for the construction of additional wind-powered generating facilities totals $515 million in 2024, $1,196 million in 2025 and $998 million in 2026.

- Repowering of wind-powered generating facilities at MidAmerican Energy totaling $47 million for 2023, $500 million for 2022 and $354 million for 2021. Planned spending for repowering totals $228 million in 2024, $382 million in 2025 and $601 million in 2026. MidAmerican Energy expects its repowered facilities to meet IRS guidelines for the re-establishment of PTCs 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 $735 million for 2023, $23 million for 2022 and $118 million for 2021. PacifiCorp placed in-service 42 MWs at the Foote Creek III and Foote Creek IV wind-powered generating facilities in 2023 and 516 MWs of new wind-powered generating facilities in 2021. Planned spending for the construction of additional wind-powered generating facilities and those at acquired sites totals $478 million in 2024, $238 million in 2025 and $95 million in 2026 and is primarily for the Rock River I, Rock Creek I and Rock Creek II wind-powered generating facilities totaling approximately 640 MWs that are expected to be placed in-service in 2024 through 2025.
- Construction of wind-powered generating facilities at BHE Renewables totaling $155 million for 2021. In May 2021, BHE Renewables completed the asset acquisition of a 54-MW wind-powered generating facility located in Iowa. In December 2021, BHE Renewables completed asset acquisitions of 158-MW and 200-MW wind-powered generating facilities located in Texas.
- Repowering of wind-powered generating facilities at BHE Renewables totaling $39 million for 2023 and $45 million in 2022. BHE Renewables repowered facilities were placed in-service in 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 and pumped hydro 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 will be developed in Clark County, Nevada, with commercial operation expected by early 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 with commercial operation being reached in December of 2023, a planned 400-MW battery energy storage system co-located with a 400MW solar photovoltaic facility that would be developed in Churchill County, Nevada with ownership share between Nevada Power and Sierra Pacific to be approved by the PUCN, with commercial operation expected by early 2026 and other planned electric battery storage systems.
- Solar generation includes growth expenditures, including spending for the following:
  - Construction and operation of solar-powered generating facilities at MidAmerican Energy primarily consisting of 141 MWs of small- and utility-scale solar generation, all of which were placed in-service in 2022, with total spend of $13 million in 2023, $119 million in 2022 and $132 million in 2021. Planned spending for the construction and operation of additional solar-powered generating facilities totals $14 million in 2024, $82 million in 2025 and $30 million in 2026.
  - Construction of solar-powered generating facility at the Nevada Utilities includes expenditures for a 150-MW solar photovoltaic facility with an additional 100 MWs of co-located battery storage that will be developed in Clark County, Nevada, with commercial operation expected by early 2024. Also included is a planned 400-MW of co-located battery storage that would be developed in Churchill County, Nevada with ownership share between Nevada Power and Sierra Pacific to be approved by the PUCN, with commercial operation expected by early 2027 and other planned solar generating facilities.
  - Construction of solar-powered generating facilities at BHE Renewables' includes expenditures for a 48-MW solar photovoltaic facility with an additional 52 MWs of capacity of co-located battery storage in Kern County, California, with commercial operation expected in the fourth quarter of 2024, with total spend of $60 million for 2023 and $22 million for 2022. Planned spending totals $139 million in 2024.

- Wildfire mitigation includes operating expenditures, including spending for the following:
    - Expenditures at PacifiCorp totaling $325 million in 2023, $159 million in 2022 and $64 million in 2021. Planned spending totals $374 million in 2024, $324 million in 2025 and $319 million in 2026 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 $20 million in 2023, $20 million in 2022 and $5 million in 2021. Planned spending totals $25 million in 2024, $31 million in 2025 and $36 million in 2026 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, 2023, 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 $127 million and letters of credit outstanding of $88 million. As of December 31, 2023, the Company's pro-rata share of such short- and long-term debt was $1.4 billion, unused revolving credit facilities was $64 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 $39.6 billion on long-term debt, including $2.3 billion due in 2024.

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.

Quad Cities Generating Station Operating Status

Constellation Energy Generation, LLC ("Constellation Energy"), the operator of Quad Cities Generating Station Units 1 and 2 ("Quad Cities Station") of which MidAmerican Energy has a 25% ownership interest, receives financial support for continued operation of Quad Cities Station from the zero emission standard enacted by the Illinois legislature in December 2016. 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. The proceeds from the ZECs provide Constellation Energy additional revenue through 2027 as an incentive for continued operation of Quad Cities Station. MidAmerican Energy does not receive additional revenue from the subsidy.

The PJM Interconnection, L.L.C. ("PJM") capacity market includes a Minimum Offer Price Rule ("MOPR"). If a generation resource is subjected to a MOPR, its offer price in the market is adjusted to effectively remove the revenues it receives through a state government-provided financial support program like the Illinois zero emission standard, resulting in a higher offer that may not clear the capacity market. Prior to December 19, 2019, the PJM MOPR applied only to certain new gas-fueled resources.

On December 19, 2019, the FERC issued an order requiring the PJM to broadly apply the MOPR to all new and existing resources, including nuclear. This greatly expanded the breadth and scope of the PJM's MOPR, which became effective as of the PJM's capacity auction for the 2022-2023 planning year. While the FERC included some limited exemptions, no exemptions were available to state-supported nuclear resources, such as Quad Cities Station. The FERC denied rehearing of that order on April 16, 2020. A number of parties, including Constellation Energy, have filed petitions for review of the FERC's orders in this proceeding, which remain pending before the Court of Appeals for the Seventh Circuit. MidAmerican Energy cannot predict the outcome of this proceeding.

While this litigation is pending, the MOPR applied to Quad Cities Station in the capacity auction for the 2022-2023 planning year in May 2021, which prevented Quad Cities Station from clearing in that capacity auction.
At the direction of the PJM Board of Managers, the PJM and its stakeholders developed further MOPR reforms to ensure that the capacity market rules respect and accommodate state resource preferences such as the ZEC programs. The PJM filed related tariff revisions with the FERC on July 30, 2021, and, on September 29, 2021, the PJM's proposed MOPR reforms became effective by operation of law. Under the new tariff provisions, the MOPR applied in the capacity auction for the 2023-2024 delivery year but did not restrict the offers of Quad Cities Station, which cleared in the capacity auction. Requests for rehearing of the FERC's notice establishing the effective date for the PJM's proposed market reforms were filed in October 2021 and denied by operation of law on November 4, 2021. Several parties have filed petitions for review of the FERC's orders in this proceeding, which remain pending before the Court of Appeals for the Third Circuit.

Assuming the continued effectiveness of the Illinois zero emission standard, Constellation Energy no longer considers Quad Cities Station to be at heightened risk for early retirement. However, to the extent the Illinois zero emission standard does not operate as expected over its full term, Quad Cities Station would be at heightened risk for early retirement. The FERC provided no new mechanism for accommodating state-supported resources like Quad Cities Station other than the existing Fixed Resource Requirement ("FRR") mechanism under which an entire utility zone would be removed from PJM's capacity auction along with sufficient resources to support the load in such zone. Depending on the outcome of the proceedings related to the PJM MOPR, the continued effectiveness of the Illinois zero emission standard may be undermined unless the PJM adopts further changes to the MOPR or Illinois implements an FRR mechanism, under which Quad Cities Station would be removed from the PJM's capacity auction.

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, 2023, 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, 2023, the Company would have been required to post $446 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 $5.6 billion and total regulatory liabilities were $6.8 billion as of December 31, 2023. 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, 2023 includes goodwill of acquired businesses of $11.5 billion. The Company evaluates goodwill for impairment at least annually and completed its annual review as of October 31, 2023. Additionally, no indicators of impairment were identified as of December 31, 2023. 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, 2023, the Company recognized a net asset totaling $302 million for the funded status of the defined benefit pension and other postretirement benefit plans. As of December 31, 2023, amounts not yet recognized as a component of net periodic benefit cost that were included in net regulatory assets totaled $282 million and in AOCI totaled $570 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, 2023.

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 2028, 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					
	Pension Plans		Other Postretirement Benefit Plans		United Kingdom Pension Plan	
	+0.5%	-0.5%	+0.5%	-0.5%	+0.5%	-0.5%
Effect on December 31, 2023						
Benefit Obligations:						
Discount rate	$ (78)	$ 85	$ (21)	$ 22	$ (75)	$ 83
Effect on 2023 Periodic Cost:						
Discount rate	$ 7	$ —	$ —	$ (1)	$ (6)	$ 6
Expected rate of return on plan assets	(10)	10	(3)	3	(4)	4

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 2017 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, 2023, these amounts were recognized as a net regulatory liability of $2.3 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, equity prices, 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 Company also provides nonregulated retail electricity and natural gas services in competitive markets. 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 $23 million and $(88) million, respectively, as of December 31, 2023 and 2022, 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, 2023:			
Not designated as hedging contracts	$ (121)	$ (14)	$ (228)
Designated as hedging contracts	11	19	3
Total commodity derivative contracts	$ (110)	$ 5	$ (225)
As of December 31, 2022:			
Not designated as hedging contracts	$ 335	$ 520	$ 150
Designated as hedging contracts	12	40	(16)
Total commodity derivative contracts	$ 347	$ 560	$ 134

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, 2023 and 2022, a net regulatory asset of $166 million and a net regulatory liability of $231 million, respectively, was recorded related to the net derivative liability of $121 million and net derivative asset of $335 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, 2023 and 2022, the Company had short- and long-term variable-rate obligations totaling $5.0 billion and $3.2 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, 2023 and 2022.

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, 2023 and 2022, the Company had variable-to-fixed interest rate swaps with notional amounts of $426 million and $481 million, respectively, £163 million and £178 million, respectively, and A$161 million and A$167 million, respectively, to protect the Company against an increase in interest rates. Additionally, as of December 31, 2023 and 2022, the Company had mortgage commitments, net, with notional amounts of $406 million and $438 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 $78 million and $108 million as of December 31, 2023 and 2022, 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, 2023 and 2022, 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.

Equity Price Risk

Market prices for equity securities are subject to fluctuation and consequently the amount realized in the subsequent sale of an investment may significantly differ from the reported market value. Fluctuation in the market price of a security may result from perceived changes in the underlying economic characteristics of the investee, the relative price of alternative investments and general market conditions.

As of December 31, 2023 and 2022, the Company's investment in BYD Company Limited common stock represented approximately 76% and 86%, respectively, of the total fair value of the Company's equity securities. The majority of the Company's remaining equity securities are held in a trust related to the decommissioning of nuclear generation assets and the realized and unrealized gains and losses are recorded as a net regulatory liability since the Company expects to recover costs for these activities through regulated rates. The following table summarizes the Company's investment in BYD Company Limited as of December 31, 2023 and 2022 and the effects of a hypothetical 30% increase and a 30% decrease in market price as of those dates. The selected hypothetical change does not reflect what could be considered the best or worst case scenarios (dollars in millions).

	Fair Value	Hypothetical Price Change	Estimated Fair Value after Hypothetical Change in Prices	Hypothetical Percentage Increase (Decrease) in BHE Shareholders' Equity
As of December 31, 2023	$ 2,218	30% increase	$ 2,883	1 %
		30% decrease	1,553	(1)
As of December 31, 2022	$ 3,763	30% increase	$ 4,892	1 %
		30% decrease	2,634	(1)

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, 2023, 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 $840 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 $16 million in 2023.

BHE Canada's functional currency is the Canadian dollar. As of December 31, 2023, 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 $453 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 $18 million in 2023.

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, 2023, 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, 2023, MidAmerican Energy's aggregate direct credit exposure from electric wholesale marketing counterparties was not material.

As of December 31, 2023, 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 2023, E.ON and certain of its affiliates and British Gas Trading Limited represented approximately 19% and 15%, 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 $666 million for the year ended December 31, 2023.

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 $1,022 million for the year ended December 31, 2023.

Item 8. Financial Statements and Supplementary Data

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, 2023 and 2022, 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, 2023, 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, 2023 and 2022, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2023, 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 audit 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 the potential loss or range of potential loss and disclose any material amounts.

Management has recorded estimated liabilities and receivables, which represent its best estimate of probable losses and expected insurance recoveries 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 and insurance recoveries. 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 insurance recoveries, and related disclosures for wildfire-related contingencies included the following, among others:

- We evaluated management's judgments related to whether a loss was probable or reasonably possible for the Wildfires by inquiring of management and the Company's external and internal legal counsel regarding the likelihood 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 management's judgments related to whether certain insurance recoveries were probable of collection by inquiring of management and the Company's external and internal legal counsel regarding the amounts of insurance recoveries recorded or disclosed. With the assistance of our insurance specialists, we tested certain significant assumptions used in the determination of collectability, including obtaining and reading relevant insurance policies to determine whether the types of insurance claims are included or excluded from coverage. We compared a sample of subsequent insurance recoveries collected to recorded amounts.
- 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 23, 2024

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,	
	2023	**2022**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,565	$ 1,591
Investments and restricted cash and cash equivalents	1,253	2,141
Trade receivables, net	2,667	2,876
Inventories	1,509	1,256
Mortgage loans held for sale	451	474
Regulatory assets	1,398	1,319
Other current assets	1,355	1,345
Total current assets	10,198	11,002
Property, plant and equipment, net	99,248	93,043
Goodwill	11,547	11,489
Regulatory assets	4,167	3,743
Investments and restricted cash and cash equivalents and investments	9,510	11,273
Other assets	3,170	3,290
Total assets	$ 137,840	$ 133,840

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)

	As of December 31,	
	2023	**2022**
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 3,175	$ 2,679
Accrued interest	625	558
Accrued property, income and other taxes	828	746
Accrued employee expenses	354	333
Short-term debt	4,148	1,119
Current portion of long-term debt	2,740	3,201
Other current liabilities	1,551	1,677
Total current liabilities	13,421	10,313
BHE senior debt	13,101	13,096
BHE junior subordinated debentures	100	100
Subsidiary debt	36,231	35,238
Regulatory liabilities	6,644	7,070
Deferred income taxes	12,437	12,678
Other long-term liabilities	6,166	4,706
Total liabilities	88,100	83,201
Commitments and contingencies (Note 16)		
Equity:		
BHE shareholders' equity:		
Preferred stock - 100 shares authorized, $0.01 par value, 0 and 1 shares issued and outstanding	—	850
Common stock - 115 shares authorized, no par value, 76 shares issued and outstanding	—	—
Additional paid-in capital	5,573	6,298
Retained earnings	44,765	41,833
Accumulated other comprehensive loss, net	(1,904)	(2,149)
Total BHE shareholders' equity	48,434	46,832
Noncontrolling interests	1,306	3,807
Total equity	49,740	50,639
Total liabilities and equity	$ 137,840	$ 133,840

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,		
	2023	**2022**	**2021**
Operating revenue:			
Energy	$ 21,280	$ 21,069	$ 18,935
Real estate	4,322	5,268	6,215
Total operating revenue	25,602	26,337	25,150
Operating expenses:			
Energy:			
Cost of sales	7,057	6,757	5,504
Operations and maintenance	4,779	4,153	3,991
Wildfire losses, net of recoveries (Note 16)	1,677	64	—
Depreciation and amortization	4,170	4,230	3,829
Property and other taxes	823	775	789
Real estate	4,316	5,117	5,710
Total operating expenses	22,822	21,096	19,823
Operating income	2,780	5,241	5,327
Other income (expense):			
Interest expense	(2,415)	(2,216)	(2,118)
Capitalized interest	132	76	64
Allowance for equity funds	267	167	126
Interest and dividend income	412	154	89
Gains (losses) on marketable securities, net	669	(2,002)	1,823
Other, net	116	(7)	(17)
Total other income (expense)	(819)	(3,828)	(33)
Income before income tax expense (benefit) and equity income (loss)	1,961	1,413	5,294
Income tax expense (benefit)	(1,699)	(1,916)	(1,132)
Equity income (loss)	(288)	(185)	(237)
Net income	3,372	3,144	6,189
Net income attributable to noncontrolling interests	352	423	399
Net income attributable to BHE shareholders	3,020	2,721	5,790
Preferred dividends	34	46	121
Earnings on common shares	$ 2,986	$ 2,675	$ 5,669

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,		
	2023	**2022**	**2021**
Net income	$ 3,372	$ 3,144	$ 6,189
Other comprehensive income (loss), net of tax:			
Unrecognized amounts on retirement benefits, net of tax of $(13), $(23) and $55	(36)	(72)	174
Foreign currency translation adjustment	346	(810)	(24)
Unrealized (losses) gains on cash flow hedges, net of tax of $(13), $20 and $10	(64)	76	67
Total other comprehensive income (loss), net of tax	246	(806)	217
Comprehensive income	3,618	2,338	6,406
Comprehensive income attributable to noncontrolling interests	352	426	404
Comprehensive income attributable to BHE shareholders	$ 3,266	$ 1,912	$ 6,002

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							
	Preferred Stock	Common Stock	Additional Paid-in Capital	Long-term Income Tax Receivable	Retained Earnings	Accumulated Other Comprehensive Loss, Net	Noncontrolling Interests	Total Equity
Balance, December 31, 2020	$ 3,750	$ —	$ 6,377	$ (658)	$ 35,093	$ (1,552)	$ 3,967	$ 46,977
Net income	—	—	—	—	5,790	—	397	6,187
Other comprehensive income	—	—	—	—	—	212	5	217
Long-term income tax receivable adjustments	—	—	—	(86)	(8)	—	—	(94)
Preferred stock redemptions	(2,100)	—	—	—	—	—	—	(2,100)
Preferred stock dividend	—	—	—	—	(121)	—	—	(121)
Distributions	—	—	—	—	—	—	(478)	(478)
Contributions	—	—	—	—	—	—	9	9
Other equity transactions	—	—	(3)	—	—	—	(5)	(8)
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 purchases	—	—	(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

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, 2023	2022	2021
Cash flows from operating activities:			
Net income	$ 3,372	$ 3,144	$ 6,189
Adjustments to reconcile net income to net cash flows from operating activities:			
(Gains) losses on marketable securities, net	(669)	2,002	(1,823)
Depreciation and amortization	4,220	4,286	3,881
Allowance for equity funds	(267)	(167)	(126)
Equity (income) loss, net of distributions	415	319	380
Net power cost deferrals	(629)	(1,290)	(520)
Amortization of net power cost deferrals	354	357	107
Other changes in regulatory assets and liabilities	(260)	(146)	(255)
Deferred income taxes and investment tax credits, net	(257)	(467)	646
Other, net	(46)	59	(57)
Changes in other operating assets and liabilities, net of effects from acquisitions:			
Trade receivables and other assets	(134)	150	553
Derivative collateral, net	(226)	121	82
Pension and other postretirement benefit plans	(10)	(27)	(39)
Accrued property, income and other taxes, net	(58)	397	(489)
Accounts payable and other liabilities	280	579	163
Wildfires insurance receivable	(253)	(130)	—
Wildfires liability	1,300	172	—
Net cash flows from operating activities	7,132	9,359	8,692
Cash flows from investing activities:			
Capital expenditures	(9,148)	(7,505)	(6,611)
Acquisitions, net of cash acquired	—	(314)	(122)
Purchases of marketable securities	(314)	(574)	(297)
Proceeds from sales of marketable securities	2,520	2,464	273
Purchases of U.S. Treasury Bills	(4,282)	(1,918)	—
Proceeds from sales of U.S. Treasury Bills	1,809	—	—
Proceeds from maturities of U.S. Treasury Bills	3,507	—	—
Proceeds from other investments	4	6	1,300
Equity method investments	(12)	119	(212)
Other, net	17	(28)	(94)
Net cash flows from investing activities	(5,899)	(7,750)	(5,763)
Cash flows from financing activities:			
Preferred stock redemptions	(850)	(800)	(2,100)
Preferred dividends	(38)	(50)	(132)
Common stock purchases	—	(870)	—
Proceeds from BHE senior debt	—	986	—
Repayments of BHE senior debt	(900)	—	(450)
Proceeds from subsidiary debt	4,084	2,887	2,409
Repayments of subsidiary debt	(2,821)	(1,494)	(2,024)
Net proceeds from (repayments of) short-term debt	3,024	(867)	(276)
Purchase of Cove Point noncontrolling interest	(3,300)	—	—
Distributions to noncontrolling interests	(395)	(524)	(488)
Other, net	(54)	(274)	(70)
Net cash flows from financing activities	(1,250)	(1,006)	(3,131)
Effect of exchange rate changes	11	(30)	1
Net change in cash and cash equivalents and restricted cash and cash equivalents	(6)	573	(201)
Cash and cash equivalents and restricted cash and cash equivalents at beginning of period	1,817	1,244	1,445
Cash and cash equivalents and restricted cash and cash equivalents at end of period	$ 1,811	$ 1,817	$ 1,244

The accompanying notes are an integral part of these consolidated financial statements.

(1) Organization and Operations

Berkshire Hathaway Energy Company ("BHE") is a holding company that owns a highly diversified portfolio of locally managed and operated businesses principally engaged in the energy industry (collectively with its subsidiaries, the "Company") and is a consolidated subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway").

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, owns 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, 2023 and 2022, 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,	
	2023	**2022**
Cash and cash equivalents	$ 1,565	$ 1,591
Investments and restricted cash and cash equivalents	224	173
Investments and restricted cash and cash equivalents and investments	22	53
Total cash and cash equivalents and restricted cash and cash equivalents	$ 1,811	$ 1,817

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 change 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):

	2023	2022	2021
Beginning balance	$ 106	$ 108	$ 77
Charged to operating costs and expenses, net	68	43	81
Write-offs, net	(72)	(45)	(50)
Ending balance	$ 102	$ 106	$ 108

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.

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 $250 million and $248 million as of December 31, 2023 and 2022, respectively, and materials and supplies totaling $1,259 million and $1,008 million as of December 31, 2023 and 2022, 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 $4 million and $22 million higher as of December 31, 2023 and 2022, 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 ("AUC"). 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 ("ARO")

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, 2023. 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 2023, 2022 and 2021, 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, 2023 and 2022, trade receivables, net on the Consolidated Balance Sheets relate substantially to Customer Revenue, including unbilled revenue of $787 million and $828 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 income tax benefits and expense for 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 on the Consolidated Statements of Operations.

New Accounting Pronouncements

In March 2023, the FASB issued ASU No. 2023-02, amending FASB ASC Topic 323-740, "Investments—Equity Method and Joint Ventures—Income Taxes" which set forth the conditions needed to apply the proportional amortization method. The amendments in this update permit reporting entities to elect to account for their tax equity investments, regardless of the tax credit program from which the income tax credits are received, using the proportional amortization method if certain conditions are met. This guidance is effective for interim and annual reporting periods beginning after December 15, 2023, with early adoption permitted, and is required to be adopted either using a modified retrospective approach by means of a cumulative-effect adjustment to retained earnings as of the beginning of the fiscal year of adoption or a retrospective approach by means of a cumulative-effect adjustment to retained earnings as of the beginning of the earliest fiscal year presented. The Company has elected not to adopt this guidance and therefore this ASU will have no effect on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

In November 2023, the FASB issued 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 is currently evaluating the impact of adopting this guidance on its 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. 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 owns an aggregate of 75% of the limited partner interests, and its affiliate, Cove Point GP Holding Company, LLC, continues to own 100% of the general partner interest, of Cove Point. Prior to the Transaction, BHE owned 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 ownership 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.

In 2021, the Company completed various acquisitions totaling $122 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. As a result of the various acquisitions, the Company acquired assets of $54 million, assumed liabilities of $61 million and recognized goodwill of $129 million.

(4) Property, Plant and Equipment, Net

Property, plant and equipment, net consists of the following as of December 31 (in millions):

	Depreciable Life	2023	2022
Regulated assets:			
Utility generation, transmission and distribution systems	5-80 years	$ 96,195	$ 92,759
Interstate natural gas pipeline assets	3-80 years	19,226	18,328
		115,421	111,087
Accumulated depreciation and amortization		(36,365)	(34,599)
Regulated assets, net		79,056	76,488
Nonregulated assets:			
Independent power plants	2-50 years	8,484	8,545
Cove Point LNG facility	40 years	3,423	3,412
Other assets	2-30 years	2,874	2,693
		14,781	14,650
Accumulated depreciation and amortization		(3,856)	(3,452)
Nonregulated assets, net		10,925	11,198
		89,981	87,686
Construction work-in-progress		9,267	5,357
Property, plant and equipment, net		$ 99,248	$ 93,043

Construction work-in-progress includes $8.6 billion and $4.9 billion as of December 31, 2023 and 2022, 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, 2023 (dollars in millions):

	Company Share	Facility In Service	Accumulated Depreciation and Amortization	Construction Work-in-Progress
PacifiCorp:				
Jim Bridger Nos. 1-4	67 %	$ 1,596	$ 996	$ 26
Hunter No. 1	94	510	237	4
Hunter No. 2	60	316	151	2
Wyodak	80	491	285	—
Colstrip Nos. 3 and 4	10	262	199	—
Hermiston	50	191	111	3
Craig Nos. 1 and 2	19	372	341	—
Hayden No. 1	25	77	55	—
Hayden No. 2	13	45	32	—
Transmission and distribution facilities	Various	900	283	192
Total PacifiCorp		4,760	2,690	227
MidAmerican Energy:				
Louisa No. 1	88 %	983	531	5
Quad Cities Nos. 1 and 2(1)	25	737	496	11
Walter Scott, Jr. No. 3	79	1,017	888	14
Walter Scott, Jr. No. 4(2)	60	170	123	8
George Neal No. 4	41	330	191	6
Ottumwa No. 1(2)	52	433	299	8
George Neal No. 3	72	557	375	20
Transmission facilities	Various	274	100	3
Total MidAmerican Energy		4,501	3,003	75
NV Energy:				
Navajo	11 %	—	2	—
Valmy	50	405	351	4
On Line Transmission Line	25	172	42	1
Transmission facilities	Various	64	30	6
Total NV Energy		641	425	11
BHE Pipeline Group:				
Ellisburg Pool	39 %	33	12	—
Ellisburg Station	50	29	9	2
Harrison	50	56	19	1
Leidy	50	148	49	2
Oakford	50	216	73	4
Common Facilities	Various	275	179	—
Total BHE Pipeline Group		757	341	9
Total		$ 10,659	$ 6,459	$ 322

(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 $891 million and $183 million, respectively.

(6) Leases

The following table summarizes the Company's leases recorded on the Consolidated Balance Sheet as of December 31 (in millions):

	2023	2022
Right-of-use assets:		
Operating leases	$ 501	$ 545
Finance leases	399	418
Total right-of-use assets	$ 900	$ 963
Lease liabilities:		
Operating leases	$ 555	$ 605
Finance leases	413	432
Total lease liabilities	$ 968	$ 1,037

The following table summarizes the Company's lease costs for the years ended December 31 (in millions):

	2023	2022	2021
Variable	$ 439	$ 552	$ 611
Operating	136	136	161
Finance:			
Amortization	21	20	23
Interest	35	36	38
Short-term	46	44	15
Total lease costs	$ 677	$ 788	$ 848
Weighted-average remaining lease term (years):			
Operating leases	7.4	7.4	7.6
Finance leases	27.5	28.1	28.1
Weighted-average discount rate:			
Operating leases	4.5 %	4.1 %	4.3 %
Finance leases	8.6 %	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):

	2023	2022	2021
Cash paid for amounts included in the measurement of lease liabilities:			
Operating cash flows from operating leases	$ (138)	$ (141)	$ (163)
Operating cash flows from finance leases	(35)	(36)	(38)
Financing cash flows from finance leases	(27)	(25)	(28)
Right-of-use assets obtained in exchange for lease liabilities:			
Operating leases	$ 71	$ 131	$ 119
Finance leases	6	3	2

The Company has the following remaining lease commitments as of December 31, 2023 (in millions):

	Operating	Finance	Total
2024	$ 148	$ 63	$ 211
2025	122	62	184
2026	97	62	159
2027	71	58	129
2028	45	52	97
Thereafter	170	512	682
Total undiscounted lease payments	653	809	1,462
Less - amounts representing interest	(98)	(396)	(494)
Lease liabilities	$ 555	$ 413	$ 968

(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):

	Weighted Average Remaining Life	2023	2022
Deferred net power costs	2 years	$ 1,769	$ 1,478
Asset retirement obligations	17 years	930	835
Deferred income taxes(1)	Various	435	373
Employee benefit plans(2)	14 years	414	490
Demand side management	10 years	245	224
Unrealized losses on regulated derivative contracts	1 year	173	112
Levelized depreciation	28 years	167	151
Cost of removal	26 years	143	—
Environmental costs	30 years	139	111
Asset disposition costs	Various	135	231
Wildfire mitigation and vegetation management costs	Various	114	111
Other	Various	901	946
Total regulatory assets		$ 5,565	$ 5,062
Reflected as:			
Current assets		$ 1,398	$ 1,319
Noncurrent assets		4,167	3,743
Total regulatory assets		$ 5,565	$ 5,062

(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 $3.2 billion and $2.3 billion as of December 31, 2023 and 2022, 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	2023	2022
Cost of removal[(1)]	26 years	$ 2,741	$ 2,578
Deferred income taxes[(2)]	Various	2,733	2,901
Asset retirement obligations	30 years	364	250
Revenue sharing mechanisms	Various	243	426
Levelized depreciation	27 years	230	245
Employee benefit plans[(3)]	Various	211	180
Unrealized gains on regulated derivative contracts	1 year	7	343
Other	Various	289	446
Total regulatory liabilities		$ 6,818	$ 7,369
Reflected as:			
Current liabilities		$ 174	$ 299
Noncurrent liabilities		6,644	7,070
Total regulatory liabilities		$ 6,818	$ 7,369

(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 2017 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):

	2023	2022
Investments:		
BYD Company Limited common stock	$ 2,218	$ 3,763
U.S. Treasury Bills	996	1,931
Rabbi trusts	487	433
Other	338	335
Total investments	4,039	6,462
Equity method investments:		
BHE Renewables tax equity investments	4,058	4,535
Electric Transmission Texas, LLC	673	623
Iroquois Gas Transmission System, L.P.	599	600
Other	381	304
Total equity method investments	5,711	6,062
Restricted cash and cash equivalents and investments:		
Quad Cities Station nuclear decommissioning trust funds	767	664
Other restricted cash and cash equivalents	246	226
Total restricted cash and cash equivalents and investments	1,013	890
Total investments and restricted cash and cash equivalents and investments	$ 10,763	$ 13,414
Reflected as:		
Other current assets	$ 1,253	$ 2,141
Noncurrent assets	9,510	11,273
Total investments and restricted cash and cash equivalents and investments	$ 10,763	$ 13,414

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):

	2023	2022	2021
Unrealized gains (losses) recognized on marketable securities held at the reporting date	$ 252	$ (1,487)	$ 1,819
Net gains (losses) recognized on marketable securities sold during the period	417	(515)	4
Gains (losses) on marketable securities, net	$ 669	$ (2,002)	$ 1,823

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 2023 and 2022 and 2021. 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.

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 pipeline 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. 1-4 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, 2023, 2022 and 2021 totaled $115 million, $100 million and $132 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)
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	$ 1,565	$ 147	$ 1,203	$ 1,000	$ 254	$ 752	$ 1,080	$ 6,001
2022:								
Credit facilities(2)	$ 3,500	$ 1,200	$ 1,509	$ 650	$ 296	$ 793	$ 2,925	$ 10,873
Less:								
Short-term debt	(245)	—	—	—	(120)	(197)	(557)	(1,119)
Tax-exempt bond support and letters of credit	—	(249)	(370)	—	—	(1)	—	(620)
Net credit facilities	$ 3,255	$ 951	$ 1,139	$ 650	$ 176	$ 595	$ 2,368	$ 9,134

(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 $92 million and $55 million, respectively, drawn on capital expenditure and other uncommitted credit facilities at Northern Powergrid as of December 31, 2023 and 2022.

(3) Excludes $700 million from a credit facility at HomeServices that is unavailable due to borrowing restrictions pursuant to the credit agreement.

As of December 31, 2023, 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 2026 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, 2023 and 2022, BHE had $1,935 million and $245 million of commercial paper borrowings outstanding at a weighted average interest rate of 5.59% and 4.55%, 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, 2023 and 2022, BHE had $300 million and $450 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, 2023 and 2022, BHE had $105 million and $101 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 through December 2024 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 billion unsecured credit facility expiring in June 2026 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 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.

As of December 31, 2023, PacifiCorp had $1.6 billion of short-term debt outstanding at a weighted average rate of 6.16%, which was subsequently repaid in January 2024. As of December 31, 2022, PacifiCorp had no short-term debt outstanding.

The credit facility and the delayed draw term loan facility described in Note 11 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, 2023, PacifiCorp had $255 million of letter of credit capacity under its $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.

As of December 31, 2022, PacifiCorp had $219 million of letter of credit capacity under the $1.2 billion revolving credit facility that was in place at that time, of which $31 million was outstanding and was utilized as a standby letter of credit, and $7 million of letters of credit outstanding under committed arrangements outside of the facility in support of certain transactions required by third parties.

MidAmerican Funding

As of December 31, 2023, MidAmerican Energy has a $1.5 billion unsecured credit facility expiring in June 2026 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.

As of December 31, 2023 and 2022, 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, 2023 and 2022, MidAmerican Energy had $345 million and $371 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, 2023 and 2022, MidAmerican Energy had $55 million and $34 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 2026 and Sierra Pacific has a $400 million secured credit facility expiring in June 2026 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, 2023 and 2022, 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, 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.

As of December 31, 2022, Nevada Power had $100 million of letter of credit capacity under its $400 million secured credit facility and Sierra Pacific had $75 million of letter of credit capacity under its $250 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, 2023 and 2022, Northern Powergrid had $— million and $65 million outstanding under this facility at a weighted average interest rate of —% and 3.56%, respectively.

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. 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, 2023, BHE Canada had no borrowings outstanding under the credit facility.

As of December 31, 2023, BHE Canada had C$50 million of letter of credit capacity under its C$50 million unsecured revolving term credit facility, of which no amount was outstanding.

AltaLink

AltaLink has a C$500 million secured revolving term credit facility expiring in December 2028 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, 2023 and 2022, AltaLink had $97 million and $89 million outstanding under the facility at a weighted average interest rate of 5.24% and 4.59%, 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 2028 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, 2023 and 2022, 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, 2023 and 2022, AltaLink had C$75 million of letter of credit capacity under its C$75 million secured revolving term credit facility, of which C$1 million and C$— million were outstanding.

AltaLink Investments, L.P. has a C$300 million unsecured revolving term credit facility expiring in December 2026 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.

AltaLink Investments, L.P. also has a C$200 million revolving term credit facility. 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 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, 2023 and 2022, AltaLink Investments, L.P. had $— million and $108 million outstanding under these facilities at a weighted average interest rate of —% and 5.71%, respectively. 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, 2023 and 2022, 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 and 2022, 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

HomeServices has a $700 million unsecured 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, 2023 and 2022, HomeServices had $— million and $115 million, respectively, outstanding under its credit facility with a weighted average interest rate of —% and 5.17%, respectively. The credit facility is unavailable due to borrowing restrictions pursuant to the credit agreement.

Through its subsidiaries, HomeServices maintains mortgage lines of credit totaling $1.5 billion and $2.2 billion as of December 31, 2023 and 2022, respectively, used for mortgage banking activities that expire beginning in March 2024 through July 2024. 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, 2023 and 2022, HomeServices had $420 million and $442 million, respectively, outstanding under these mortgage lines of credit at a weighted average interest rate of 6.92% and 6.09%, respectively.

BHE Renewables Letters of Credit

As of December 31, 2023 and 2022, certain renewable projects collectively have letters of credit outstanding of $311 million and $309 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	2023	2022
2.80% Senior Notes, due 2023	$ —	$ —	$ 400
3.75% Senior Notes, due 2023	—	—	500
3.50% Senior Notes, due 2025	400	399	398
4.05% Senior Notes, due 2025	1,250	1,248	1,245
3.25% Senior Notes, due 2028	600	593	594
8.48% Senior Notes, due 2028	256	264	266
3.70% Senior Notes, due 2030	1,100	1,096	1,095
1.65% Senior Notes, due 2031	500	498	497
6.125% Senior Bonds, due 2036	1,670	1,663	1,661
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	740
4.50% Senior Notes, due 2045	750	739	738
3.80% Senior Notes, due 2048	750	736	738
4.45% Senior Notes, due 2049	1,000	990	990
4.25% Senior Notes, due 2050	900	889	889
2.85% Senior Notes, due 2051	1,500	1,488	1,487
4.60% Senior Notes, due 2053	1,000	986	987
Total BHE Senior Debt	$ 13,201	$ 13,101	$ 13,996
Reflected as:			
Current liabilities		$ —	$ 900
Noncurrent liabilities		13,101	13,096
Total BHE Senior Debt		$ 13,101	$ 13,996

Junior Subordinated Debentures

BHE junior subordinated debentures consists of the following as of December 31 (in millions):

	Par Value	2023	2022
5.00% Junior subordinated debentures, due 2057	100	100	100
Total BHE junior subordinated debentures - noncurrent	$ 100	$ 100	$ 100

The junior subordinated debentures are held by a minority shareholder and are redeemable at BHE's option at any time from and after June 15, 2037, at par plus accrued and unpaid interest. Interest expense to the minority shareholder was $5 million for each of the years ended December 31, 2023, 2022 and 2021.

(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, 2023, 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):

	Par Value	2023	2022
PacifiCorp	$ 10,493	$ 10,410	$ 9,666
MidAmerican Funding	9,115	8,992	7,954
NV Energy	4,736	4,695	4,354
Northern Powergrid	3,497	3,465	3,054
BHE Pipeline Group	4,876	5,154	5,849
BHE Transmission	3,591	3,574	3,495
BHE Renewables	2,571	2,548	3,027
HomeServices	133	133	140
Total subsidiary debt	$ 39,012	$ 38,971	$ 37,539
Reflected as:			
Current liabilities		$ 2,740	$ 2,301
Noncurrent liabilities		36,231	35,238
Total subsidiary debt		$ 38,971	$ 37,539

PacifiCorp

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	2023	2022
First mortgage bonds:			
2.95% to 8.23%, due through 2026	$ 775	$ 774	$ 1,223
2.70% to 7.70%, due 2029 to 2031	1,100	1,096	1,095
5.25% to 6.35%, due 2034 to 2038	2,350	2,341	2,340
4.10% to 6.00%, due 2039 to 2042	950	942	941
2.90% to 5.50%, due 2049 to 2054	5,100	5,039	3,849
Variable-rate series, tax-exempt bond obligations (2023-4.60% to 5.60%; 2022-3.75% to 4.10%):			
Due 2025	25	25	25
Due 2024 to 2025[(1)]	193	193	193
Total PacifiCorp	$ 10,493	$ 10,410	$ 9,666

(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 December 2023, PacifiCorp entered into a $900 million unsecured delayed draw term loan facility expiring in June 2025. Amounts borrowed under the facility bear interest at variable rates based on the Secured Overnight Financing Rate or a base rate, at PacifiCorp's option, plus a pricing margin. Subject to regulatory authority to issue long-term debt, PacifiCorp may draw all or none of the unused commitment up to three times through June 2025. As of December 31, 2023, PacifiCorp had no term loans drawn from the facility and currently has no authority to issue additional long-term debt until additional filings occur with the Oregon Public Utility Commission ("OPUC") and the Idaho Public Utilities Commission ("IPUC") and are approved as described below.

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.

Following PacifiCorp's January 2024 First Mortgage Bond issuances, PacifiCorp currently has no remaining regulatory authority from the OPUC and the IPUC to issue additional long-term debt. PacifiCorp must apply for additional issuance authority from the OPUC and IPUC and 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 through September 2026.

The issuance of PacifiCorp's first mortgage bonds is limited by available property, earnings tests and other provisions of PacifiCorp's mortgage. Approximately $36 billion of PacifiCorp's eligible property (based on original cost) was subject to the lien of the mortgage as of December 31, 2023.

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):

	Par Value	2023	2022
MidAmerican Funding:			
6.927% Senior Bonds, due 2029	$ 239	$ 240	$ 240
Fair value adjustment	—	(14)	(15)
MidAmerican Funding, net of fair value adjustments	239	226	225
MidAmerican Energy:			
First Mortgage Bonds:			
3.70%, due 2023	—	—	250
3.50%, due 2024	500	500	500
3.10%, due 2027	375	374	374
3.65%, due 2029	850	858	859
4.80%, due 2043	350	347	347
4.40%, due 2044	400	396	395
4.25%, due 2046	450	446	446
3.95%, due 2047	475	471	471
3.65%, due 2048	700	690	689
4.25%, due 2049	900	876	875
3.15%, due 2050	600	592	592
2.70%, due 2052	500	492	492
5.35%, due 2034	350	347	—
5.85%, due 2054	1,000	989	—
Notes:			
6.75% Series, due 2031	400	398	397
5.75% Series, due 2035	300	299	298
5.80% Series, due 2036	350	348	348
Transmission upgrade obligation, 3.24% to 7.84%, due 2036 to 2043	70	39	27
Tax-exempt bond obligations -			
Variable-rate tax-exempt bond obligation series: (weighted average interest rate - 2023-4.81%, 2022-3.83%), due 2023-2047	306	304	369
Total MidAmerican Energy	8,876	8,766	7,729
Total MidAmerican Funding	$ 9,115	$ 8,992	$ 7,954

In January 2024, MidAmerican Energy issued $600 million of its 5.30% First Mortgage Bonds due February 2055. MidAmerican Energy intends, within 24 months of the issuance date, to allocate an amount equal to the net proceeds to finance, in whole or in part, new or existing investments or expenditures made in one or more eligible projects in alignment with BHE's Green Financing Framework.

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 $24 billion of MidAmerican Energy's eligible property, based on original cost, was subject to the lien of the mortgage as of December 31, 2023. 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 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, 2023 and 2022. MidAmerican Energy maintains revolving credit facility agreements to provide liquidity for holders of these issues. Additionally, MidAmerican Energy's obligations associated with $30 million and $150 million of the 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	2023	2022
Nevada Power:			
General and refunding mortgage securities:			
3.700% Series CC, due 2029	$ 500	$ 498	$ 497
2.400% Series DD, due 2030	425	423	422
6.650% Series N, due 2036	367	360	360
6.750% Series R, due 2037	349	346	346
5.375% Series X, due 2040	250	248	248
5.450% Series Y, due 2041	250	240	239
3.125% Series EE, due 2050	300	298	298
5.900% Series GG, due 2053	400	394	394
6.000% Series 2023A, due 2054	500	494	—
Tax-exempt refunding revenue bond obligations:			
Fixed-rate series:			
4.125% Pollution Control Bonds Series 2017A, due 2032(1)	40	39	39
3.750% Pollution Control Bonds Series 2017, due 2036(1)	40	39	39
3.750% Pollution Control Bonds Series 2017B, due 2039(1)	13	13	13
Variable-rate 4.821% Term Loan, due 2024(2)	—	—	300
Total Nevada Power	3,434	3,392	3,195
Fair value adjustments	—	9	10
Total Nevada Power, net of fair value adjustments	3,434	3,401	3,205
Sierra Pacific:			
General and refunding mortgage securities:			
3.375% Series T, due 2023	—	—	249
2.600% Series U, due 2026	400	398	397
6.750% Series P, due 2037	252	254	254
4.710% Series W, due 2052	250	248	248
5.900% Series 2023A, due 2054	400	393	—
Total Sierra Pacific	1,302	1,293	1,148
Fair value adjustments	—	1	1
Total Sierra Pacific, net of fair value adjustment	1,302	1,294	1,149
Total NV Energy	$ 4,736	$ 4,695	$ 4,354

(1) Subject to mandatory purchase by Nevada Power in March 2026 at which date the interest rate may be adjusted.

(2) Amounts borrowed under the facility bear interest at variable rates based on SOFR or a base rate, at Nevada Power's option, plus a pricing margin.

In February 2024, Sierra Pacific entered into a re-offering of the following series of fixed-rate tax exempt bonds: $75 million of Washoe County, Nevada Water Facilities Refunding Revenue Bonds, Series 2016F, due 2036; $60 million of Washoe County, Nevada Gas and Water Facilities Refunding Revenue Bonds, Series 2016B, due 2036; $30 million of Humboldt County, Nevada Pollution Control Refunding Revenue Bonds, Series 2016B, due 2029; $30 million of Washoe County, Nevada Water Facilities Refunding Revenue Bonds, Series 2016C, due 2036; $20 million of Humboldt County, Nevada Pollution Control Refunding Revenue Bonds, Series 2016A due 2029; and $20 million of Washoe County, Nevada Water Facilities Refunding Revenue Bonds, Series 2016G, due 2036. The Humboldt County Series 2016A and Series 2016B bonds were offered at a term rate of 3.550%. The Washoe County Series 2016B and Series 2016G bonds were offered at a fixed rate of 3.625% and the Washoe County Series 2016C and Series 2016F bonds were offered at a fixed rate of 4.125%. Sierra Pacific previously purchased the bonds as required by the bond indentures. Sierra Pacific used the net proceeds of the re-offering for general corporate purposes.

The issuance of General and Refunding Mortgage Securities by the Nevada Utilities are subject to 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, 2023, approximately $10 billion of Nevada Power's and $5 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):

	Par Value(1)	2023	2022
2.50% Bonds, due 2025	$ 191	$ 191	$ 181
2.073% European Investment Bank loan, due 2025	64	65	62
2.564% European Investment Bank loans, due 2027	318	317	301
7.25% Bonds, due 2028	236	238	227
4.375% Bonds, due 2032	191	189	179
5.625% Bonds, due 2033	318	314	—
5.125% Bonds, due 2035	255	252	240
5.125% Bonds, due 2035	191	189	180
2.75% Bonds, due 2049	191	188	178
3.25% Bonds, due 2052	445	442	419
2.25% Bonds, due 2059	382	374	355
1.875% Bonds, due 2062	382	375	356
Variable-rate loan, due 2025(2)	158	158	164
Variable-rate loan, due 2026(3)	175	173	212
Total Northern Powergrid	$ 3,497	$ 3,465	$ 3,054

(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, 2023, was 6.41% (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, 2023 was 6.74% (including 1.55% margin) and the fixed interest rate was 2.45% (including 1.55% margin), resulting in a blended rate of 3.30%.

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):

	Par Value	2023	2022
Eastern Energy Gas:			
2.875% Senior Notes, due 2023	$ —	$ —	$ 250
3.55% Senior Notes, due 2023	—	—	399
2.50% Senior Notes, due 2024	600	600	598
3.60% Senior Notes, due 2024	339	339	338
3.32% Senior Notes, due 2026 (€250)(1)	276	274	267
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
EGTS:			
3.60% Senior Notes, due 2024	111	111	110
3.00% Senior Notes, due 2029	426	422	422
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	3,276	3,254	3,892
Fair value adjustments	—	312	368
Total Eastern Energy Gas, net of fair value adjustments	3,276	3,566	4,260
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	652
3.40% Senior Bonds, due 2051	550	540	540
Total Northern Natural Gas	1,600	1,588	1,589
Total BHE Pipeline Group	$ 4,876	$ 5,154	$ 5,849

(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, 2023 and 2022 that averaged 3.32%.

In January 2024, Northern Natural Gas issued $500 million of its 5.625% Senior Bonds due February 2054. Northern Natural Gas intends to use the net proceeds from the sale of the bonds for general corporate purposes, including to fund capital expenditures.

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):

	Par Value[1]	2023	2022
AltaLink, L.P.:			
Series 2013-4 Notes, 3.668%, due 2023	$ —	$ —	$ 369
Series 2014-1 Notes, 3.399%, due 2024	264	264	258
Series 2016-1 Notes, 2.747%, due 2026	264	264	258
Series 2020-1 Notes, 1.509%, due 2030	170	169	165
Series 2022-1 Notes, 4.692%, due 2032	208	207	202
Series 2006-1 Notes, 5.249%, due 2036	113	113	111
Series 2010-1 Notes, 5.381%, due 2040	94	94	92
Series 2010-2 Notes, 4.872%, due 2040	113	113	110
Series 2011-1 Notes, 4.462%, due 2041	208	207	202
Series 2012-1 Notes, 3.990%, due 2042	396	391	383
Series 2013-3 Notes, 4.922%, due 2043	264	263	258
Series 2014-3 Notes, 4.054%, due 2044	223	222	216
Series 2015-1 Notes, 4.090%, due 2045	264	263	257
Series 2016-2 Notes, 3.717%, due 2046	340	338	330
Series 2013-1 Notes, 4.446%, due 2053	189	188	184
Series 2023-1 Notes, 5.463%, due 2055	378	375	—
Series 2014-2 Notes, 4.274%, due 2064	98	98	95
Total AltaLink, L.P.	3,586	3,569	3,490
Other:			
Construction Loan, 5.620%, due 2024	5	5	5
Total BHE Transmission	$ 3,591	$ 3,574	$ 3,495

(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	2023	2022
Fixed-rate[1]:			
Bishop Hill Holdings Senior Notes, 5.125%, due 2032	$ 51	$ 50	$ 56
Solar Star Funding Senior Notes, 3.950%, due 2035	230	228	242
Solar Star Funding Senior Notes, 5.375%, due 2035	744	739	781
Grande Prairie Wind Senior Notes, 3.860%, due 2037	236	234	267
Topaz Solar Farms Senior Notes, 5.750%, due 2039	541	536	568
Topaz Solar Farms Senior Notes, 4.875%, due 2039	152	151	160
Alamo 6 Senior Notes, 4.170%, due 2042	181	179	188
Variable-rate[1]:			
TX Jumbo Road Term Loan, due 2025[2]	73	72	96
Marshall Wind Term Loan, due 2026[2]	49	49	56
Flat Top Wind I Term Loan, due 2028[2]	—	—	99
Mariah Del Norte Term Loan, due 2028[2]	—	—	54
Mariah Del Norte Term Loan, due 2032[2]	—	—	138
Pinyon Pines I and II Term Loans, due 2034[2]	314	310	322
Total BHE Renewables	$ 2,571	$ 2,548	$ 3,027

(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, 2023 and 2022 ranged from 3.23% to 3.88%. The variable interest rate on the Flat Top Wind I and Mariah Del Norte outstanding debt was 9.82% as of December 31, 2022.

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	2023	2022
Variable-rate:			
Variable-rate term loan (2023 - 6.27%, 2022 - 5.242%), due 2026[1]	$ 133	$ 133	$ 140

(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, 2024 and thereafter, excluding fair value adjustments and unamortized premiums, discounts and debt issuance costs, are as follows (in millions):

	2024	2025	2026	2027	2028	2029 and Thereafter	Total
BHE senior notes	$ —	$ 1,650	$ —	$ —	$ 856	$ 10,695	$ 13,201
BHE junior subordinated debentures	—	—	—	—	—	100	100
PacifiCorp	591	302	100	—	—	9,500	10,493
MidAmerican Funding	539	17	4	379	4	8,172	9,115
NV Energy	—	—	400	—	—	4,336	4,736
Northern Powergrid	62	449	79	318	236	2,353	3,497
BHE Pipeline Group	1,050	—	276	—	—	3,550	4,876
BHE Transmission	269	—	264	—	—	3,058	3,591
BHE Renewables	220	241	218	168	175	1,549	2,571
HomeServices	9	15	109	—	—	—	133
Totals	$ 2,740	$ 2,674	$ 1,450	$ 865	$ 1,271	$ 43,313	$ 52,313

(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 receivable from Berkshire Hathaway of $96 million and a current income tax payable to Berkshire Hathaway of $113 million for federal income tax as of December 31, 2023 and 2022, 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):

	2023	2022	2021
Current:			
Federal	$ (1,650)	$ (1,463)	$ (1,701)
State	118	(65)	(177)
Foreign	90	79	100
	(1,442)	(1,449)	(1,778)
Deferred:			
Federal	(114)	(408)	1,037
State	(275)	(49)	(476)
Foreign	33	(5)	89
	(356)	(462)	650
Investment tax credits	99	(5)	(4)
Total	$ (1,699)	$ (1,916)	$ (1,132)

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:

	2023	2022	2021
Federal statutory income tax rate	21 %	21 %	21 %
Income tax credits	(85)	(124)	(27)
Effects of ratemaking	(11)	(16)	(4)
State income tax, net of federal income tax benefit	(6)	(6)	(10)
Non-controlling interest	(4)	(6)	(2)
Income tax effect of foreign income	(1)	(4)	(1)
Tax rate change - deferred (foreign)	2	—	2
Equity loss	(3)	(3)	(1)
Other, net	—	2	1
Effective income tax rate	(87)%	(136)%	(21)%

Income tax credits relate primarily to production tax credits ("PTC") from wind- and solar-powered generating facilities owned by MidAmerican Energy, PacifiCorp 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, 2023, 2022 and 2021 totaled $1.7 billion, $1.7 billion, and $1.4 billion, respectively.

Tax rate change - deferred (foreign) includes a deferred income tax charge of $45 million in 2023, related to the United Kingdom's Energy Profits Levy. The Energy Profits Levy increased from 25% to 35%, effective January 1, 2023. It also includes a deferred income tax charge of $105 million in 2021, related to the United Kingdom's corporate income tax rate. The United Kingdom's rate increased from 19% to 25%, effective April 1, 2023, through legislation enacted in June 2021.

The net deferred income tax liability consists of the following as of December 31 (in millions):

	2023	2022
Deferred income tax assets:		
Regulatory liabilities	$ 1,248	$ 1,323
Federal, state and foreign carryforwards	774	812
AROs	318	283
Loss contingency	431	109
Other	629	632
Total deferred income tax assets	3,400	3,159
Valuation allowances	(142)	(187)
Total deferred income tax assets, net	3,258	2,972
Deferred income tax liabilities:		
Property-related items	(12,596)	(12,244)
Investments	(1,574)	(1,998)
Regulatory assets	(1,034)	(898)
Other	(491)	(510)
Total deferred income tax liabilities	(15,695)	(15,650)
Net deferred income tax liability	$ (12,437)	$ (12,678)

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, 2023 (in millions):

	Federal		State		Foreign		Total	
Net operating loss carryforwards[1]	$	119	$	9,850	$	688	$	10,657
Deferred income taxes on net operating loss carryforwards		25		547		158		730
Expiration dates		2024 - indefinite		2024 - indefinite		2028 - 2043		
Tax credits	$	15	$	29	$	—	$	44
Expiration dates		2024 - 2034		2024 - 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 Inc.'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, 2019, 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):

	2023		2022	
Beginning balance	$	68	$	97
Additions based on tax positions related to the current year		10		15
Additions for tax positions of prior years		1		—
Reductions based on tax positions related to the current year		(6)		(12)
Reductions for tax positions of prior years		—		(23)
Statute of limitations		(1)		—
Interest and penalties		1		(9)
Ending balance	$	73	$	68

As of December 31, 2023 and 2022, the Company had unrecognized tax benefits totaling $88 million and $79 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

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):

	Pension			Other Postretirement		
	2023	2022	2021	2023	2022	2021
Service cost	$ 15	$ 22	$ 30	$ 8	$ 11	$ 12
Interest cost	110	83	78	30	20	19
Expected return on plan assets	(123)	(108)	(134)	(33)	(29)	(22)
Curtailment	—	(10)	—	—	—	—
Settlement	(3)	17	3	—	—	—
Net amortization	14	19	25	(2)	(1)	(3)
Net periodic benefit cost	$ 13	$ 23	$ 2	$ 3	$ 1	$ 6

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	
	2023	2022	2023	2022
Plan assets at fair value, beginning of year	$ 2,013	$ 2,795	$ 614	$ 769
Employer contributions	14	14	6	8
Participant contributions	—	—	8	8
Actual return on plan assets	219	(491)	86	(122)
Settlement	—	(164)	—	—
Benefits paid	(177)	(141)	(49)	(49)
Plan assets at fair value, end of year	$ 2,069	$ 2,013	$ 665	$ 614

The following table is a reconciliation of the benefit obligations for the years ended December 31 (in millions):

	Pension		Other Postretirement	
	2023	2022	2023	2022
Benefit obligation, beginning of year	$ 2,040	$ 2,777	$ 569	$ 714
Service cost	15	22	8	11
Interest cost	110	83	30	20
Participant contributions	—	—	8	8
Actuarial loss (gain)	62	(524)	(1)	(155)
Amendment	—	(3)	—	20
Curtailment	—	(10)	—	—
Settlement	—	(164)	—	—
Benefits paid	(177)	(141)	(49)	(49)
Benefit obligation, end of year	$ 2,050	$ 2,040	$ 565	$ 569
Accumulated benefit obligation, end of year	$ 2,013	$ 2,003		

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	
	2023	2022	2023	2022
Plan assets at fair value, end of year	$ 2,069	$ 2,013	$ 665	$ 614
Benefit obligation, end of year	2,050	2,040	565	569
Funded status	$ 19	$ (27)	$ 100	$ 45
Amounts recognized on the Consolidated Balance Sheets:				
Other assets	$ 160	$ 125	$ 104	$ 52
Other current liabilities	(13)	(13)	—	—
Other long-term liabilities	(128)	(139)	(4)	(7)
Amounts recognized	$ 19	$ (27)	$ 100	$ 45

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 $341 million and $300 million as of December 31, 2023 and 2022, 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 fair value of plan assets, projected benefit obligation and accumulated benefit obligation for (1) pension and other postretirement benefit plans with a projected benefit obligation in excess of the fair value of plan assets and (2) pension plans with an accumulated benefit obligation in excess of the fair value of plan assets as of December 31 are as follows (in millions):

	Pension		Other Postretirement	
	2023	2022	2023	2022
Fair value of plan assets	$ —	$ 490	$ —	$ 240
Projected benefit obligation	$ 141	$ 643	$ 4	$ 247
Fair value of plan assets	$ —	$ —		
Accumulated benefit obligation	$ 141	$ 142		

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	
	2023	2022	2023	2022
Net loss (gain)	$ 325	$ 365	$ (88)	$ (38)
Prior service (credit) cost	(3)	(4)	20	21
Regulatory deferrals	22	29	—	1
Total	$ 344	$ 390	$ (68)	$ (16)

A reconciliation of the amounts not yet recognized as components of net periodic benefit cost for the years ended December 31, 2023 and 2022 is as follows (in millions):

	Regulatory Assets (Liabilities)	Accumulated Other Comprehensive Loss (Income)	Total
Pension			
Balance, December 31, 2021	$ 331	$ 22	$ 353
Net loss (gain) arising during the year	96	(20)	76
Net prior service credit arising during the year	(3)	—	(3)
Settlement	(17)	—	(17)
Net amortization	(17)	(2)	(19)
Total	59	(22)	37
Balance, December 31, 2022	390	—	390
Net gain arising during the year	(35)	—	(35)
Settlement	3	—	3
Net amortization	(13)	(1)	(14)
Total	(45)	(1)	(46)
Balance, December 31, 2023	$ 345	$ (1)	$ 344

	Regulatory Assets (Liabilities)	Accumulated Other Comprehensive Loss (Income)	Total
Other Postretirement			
Balance, December 31, 2021	$ (34)	$ 1	$ (33)
Net gain arising during the year	—	(4)	(4)
Net prior service cost arising during the year	19	1	20
Net amortization	1	—	1
Total	20	(3)	17
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)

Plan Assumptions

Weighted-average assumptions used to determine benefit obligations and net periodic benefit cost were as follows:

	Pension			Other Postretirement		
	2023	**2022**	**2021**	**2023**	**2022**	**2021**
Benefit obligations as of December 31:						
Discount rate	5.36 %	5.65 %	2.98 %	5.35 %	4.54 %	2.95 %
Rate of compensation increase	3.00 %	3.00 %	2.75 %	N/A	N/A	N/A
Interest crediting rates for cash balance plan						
2021	N/A	N/A	2.45 %	N/A	N/A	N/A
2022	N/A	3.25 %	2.56 %	N/A	N/A	N/A
2023	4.19 %	4.25 %	2.56 %	N/A	N/A	N/A
2024	4.58 %	4.25 %	2.83 %	N/A	N/A	N/A
2025	4.58 %	3.65 %	2.83 %	N/A	N/A	N/A
2026 and beyond	3.73 %	3.65 %	2.83 %	N/A	N/A	N/A
Net periodic benefit cost for the years ended December 31:						
Discount rate	5.65 %	2.98 %	2.60 %	5.58 %	2.95 %	2.59 %
Expected return on plan assets	6.10 %	4.30 %	5.39 %	5.84 %	4.20 %	3.35 %
Rate of compensation increase	3.00 %	2.75 %	2.75 %	N/A	N/A	N/A
Interest crediting rate for cash balance plan	4.19 %	3.25 %	2.45 %	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.

	2023	**2022**
Assumed healthcare cost trend rates as of December 31:		
Healthcare cost trend rate assumed for next year	6.44 %	6.50 %
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	2028	2028

Contributions and Benefit Payments

Employer contributions to the pension and other postretirement benefit plans are expected to be $13 million and $5 million, respectively, during 2024. 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 2024 through 2028 and for the five years thereafter are summarized below (in millions):

	Projected Benefit Payments	
	Pension	Other Postretirement
2024	$ 187	$ 54
2025	183	54
2026	181	53
2027	175	54
2028	169	52
2029-2033	774	231

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, 2023:

	Pension	Other Postretirement
	%	%
PacifiCorp:		
Debt securities[1]	73	79
Equity securities[1]	22	21
Limited partnership interests	5	0
MidAmerican Energy:		
Debt securities[1]	40-60	25-35
Equity securities[1]	30-60	65-75
Other	0-15	0-5
NV Energy:		
Debt securities[1]	65-80	68-88
Equity securities[1]	20-35	12-32

(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, 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	$ 319	$ 804	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			$ 2,069
As of December 31, 2022:			
Cash equivalents	$ —	$ 51	$ 51
Debt securities:			
U.S. government obligations	109	—	109
Corporate obligations	—	613	613
Municipal obligations	—	43	43
Agency, asset and mortgage-backed obligations	—	81	81
Equity securities:			
U.S. companies	198	—	198
International companies	1	—	1
Total assets in the fair value hierarchy	$ 308	$ 788	1,096
Investment funds[2] measured at net asset value			885
Limited partnership interests[3] measured at net asset value			32
Total assets measured at fair value			$ 2,013

(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 51% and 49%, respectively, for 2023 and 53% and 47%, respectively, for 2022. Additionally, these funds are invested in U.S. and international securities of approximately 94% and 6%, respectively, for 2023 and 95% and 5%, respectively, for 2022.

(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
As of December 31, 2023:			
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	$ 372	$ 160	532
Investment funds[2] measured at net asset value			133
Total assets measured at fair value			$ 665
As of December 31, 2022:			
Cash equivalents	$ 15	$ 9	$ 24
Debt securities:			
U.S. government obligations	8	—	8
Corporate obligations	—	52	52
Municipal obligations	—	35	35
Agency, asset and mortgage-backed obligations	—	49	49
Equity securities:			
U.S. companies	7	—	7
Investment funds[2]	307	—	307
Total assets in the fair value hierarchy	$ 337	$ 145	482
Investment funds[2] measured at net asset value			132
Total assets measured at fair value			$ 614

(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 55% and 45%, respectively, for 2023 and 55% and 45%, respectively, for 2022. Additionally, these funds are invested in U.S. and international securities of approximately 88% and 12%, respectively, for 2023 and 88% and 12%, respectively, for 2022.

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

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):

	2023	2022	2021
Service cost	$ 6	$ 14	$ 16
Interest cost	57	35	31
Expected return on plan assets	(80)	(92)	(111)
Settlement	—	—	10
Net amortization	26	24	55
Net periodic benefit cost (credit)	$ 9	$ (19)	$ 1

Funded Status

The following table is a reconciliation of the fair value of plan assets for the years ended December 31 (in millions):

	2023	2022
Plan assets at fair value, beginning of year	$ 1,363	$ 2,363
Employer contributions	13	15
Participant contributions	1	1
Actual return on plan assets	52	(671)
Benefits paid	(97)	(109)
Foreign currency exchange rate changes	70	(236)
Plan assets at fair value, end of year	$ 1,402	$ 1,363

The following table is a reconciliation of the benefit obligation for the years ended December 31 (in millions):

	2023	2022
Benefit obligation, beginning of year	$ 1,175	$ 2,003
Service cost	6	14
Interest cost	57	35
Participant contributions	1	1
Actuarial loss (gain)	1	(596)
Amendment	16	27
Benefits paid	(97)	(109)
Foreign currency exchange rate changes	60	(200)
Benefit obligation, end of year	$ 1,219	$ 1,175
Accumulated benefit obligation, end of year	$ 1,103	$ 1,060

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):

	2023	2022
Plan assets at fair value, end of year	$ 1,402	$ 1,363
Benefit obligation, end of year	1,219	1,175
Funded status	$ 183	$ 188
Amounts recognized on the Consolidated Balance Sheets:		
Other assets	$ 183	$ 188

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):

	2023	2022
Net loss	$ 532	$ 499
Prior service cost	44	30
Total	$ 576	$ 529

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):

	2023	2022
Balance, beginning of year	$ 529	$ 405
Net loss arising during the year	29	167
Net prior service cost arising during the year	16	27
Net amortization	(26)	(24)
Foreign currency exchange rate changes	28	(46)
Total	47	124
Balance, end of year	$ 576	$ 529

Plan Assumptions

Assumptions used to determine benefit obligations and net periodic benefit cost were as follows:

	2023	2022	2021
Benefit obligations as of December 31:			
Discount rate	4.55 %	4.80 %	1.95 %
Rate of compensation increase	3.00 %	3.20 %	3.45 %
Rate of future price inflation	2.75 %	2.95 %	2.95 %
Net periodic benefit cost for the years ended December 31:			
Discount rate	4.80 %	1.95 %	1.40 %
Expected return on plan assets	6.00 %	4.40 %	4.85 %
Rate of compensation increase	3.20 %	3.45 %	3.05 %
Rate of future price inflation	2.95 %	2.95 %	2.55 %

Contributions and Benefit Payments

Employer contributions to the UK Plan are expected to be £9 million during 2024. The expected benefit payments to participants in the UK Plan for 2024 through 2028 and for the five years thereafter, excluding lump sum settlement elections and using the foreign currency exchange rate as of December 31, 2023, are summarized below (in millions):

2024	$ 74
2025	76
2026	78
2027	79
2028	81
2029-2033	437

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, 2023:

	%
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, 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	$ 587	$ 560	$ 136	1,283
Investment funds[2] measured at net asset value				119
Total assets measured at fair value				$ 1,402
As of December 31, 2022:				
Cash equivalents	$ 1	$ 29	$ —	$ 30
Debt securities:				
United Kingdom government obligations	711	—	—	711
Equity securities:				
Investment funds[2]	—	312	—	312
Real estate funds	—	—	214	214
Total	$ 712	$ 341	$ 214	1,267
Investment funds[2] measured at net asset value				96
Total assets measured at fair value				$ 1,363

(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 14% and 86%, respectively, for 2023 and 25% and 75%, respectively, for 2022.

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		
	2023	2022	2021
Beginning balance	$ 214	$ 269	$ 237
Actual return on plan assets still held at period end	(87)	(27)	35
Foreign currency exchange rate changes	9	(28)	(3)
Ending balance	$ 136	$ 214	$ 269

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 $177 million, $159 million and $137 million for the years ended December 31, 2023, 2022 and 2021, 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 $2.7 billion and $2.6 billion as of December 31, 2023 and 2022, respectively.

The following table presents the Company's ARO liabilities by asset type as of December 31 (in millions):

	2023	2022
Wind-powered generating facilities	$ 452	$ 353
Quad Cities Station	407	417
Fossil-fueled generating facilities	402	396
Solar-powered generating facilities	36	30
Offshore pipeline facilities	15	14
Other	116	118
Total asset retirement obligations	$ 1,428	$ 1,328
Quad Cities Station nuclear decommissioning trust funds	$ 767	$ 664

The following table reconciles the beginning and ending balances of the Company's ARO liabilities for the years ended December 31 (in millions):

	2023	2022
Beginning balance	$ 1,328	$ 1,340
Change in estimated costs	54	2
Acquisitions	—	29
Additions	56	32
Retirements	(64)	(122)
Accretion	54	47
Ending balance	$ 1,428	$ 1,328
Reflected as:		
Other current liabilities	$ 34	$ 76
Other long-term liabilities	1,394	1,252
Total ARO liability	$ 1,428	$ 1,328

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.

(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, 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
	$ 5,523	$ 685	$ 11	$ (31)	$ 6,188
Liabilities:					
Commodity derivatives	$ (7)	$ (134)	$ (95)	$ 54	$ (182)
Foreign currency exchange rate derivatives	—	(8)	—	—	(8)
Interest rate derivatives	—	(7)	—	4	(3)
	$ (7)	$ (149)	$ (95)	$ 58	$ (193)

	Input Levels for Fair Value Measurements				
	Level 1	Level 2	Level 3	Other[(1)]	Total
As of December 31, 2022:					
Assets:					
Commodity derivatives	$ 6	$ 614	$ 51	$ (194)	$ 477
Interest rate derivatives	50	54	8	—	112
Mortgage loans held for sale	—	474	—	—	474
Money market mutual funds	1,178	—	—	—	1,178
Debt securities:					
U.S. government obligations	2,146	—	—	—	2,146
International government obligations	—	1	—	—	1
Corporate obligations	—	70	—	—	70
Municipal obligations	—	3	—	—	3
Agency, asset and mortgage-backed obligations	—	1	—	—	1
Equity securities:					
U.S. companies	360	—	—	—	360
International companies	3,771	—	—	—	3,771
Investment funds	231	—	—	—	231
	$ 7,742	$ 1,217	$ 59	$ (194)	$ 8,824
Liabilities:					
Commodity derivatives	$ (8)	$ (206)	$ (110)	$ 106	$ (218)
Foreign currency exchange rate derivatives	—	(21)	—	—	(21)
Interest rate derivatives	—	(2)	(2)	1	(3)
	$ (8)	$ (229)	$ (112)	$ 107	$ (242)

(1) Represents netting under master netting arrangements and a net cash collateral receivable of $27 million and payable of $87 million as of December 31, 2023 and 2022, 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		
	2023	2022	2021	2023	2022	2021
Beginning balance	$ (59)	$ (151)	$ 116	$ 6	$ 19	$ 62
Changes included in earnings[1]	9	(85)	(43)	1	(13)	(43)
Changes in fair value recognized in OCI	(3)	9	(13)	—	—	—
Changes in fair value recognized in net regulatory assets	(256)	(52)	(118)	—	—	—
Purchases	2	3	(76)	—	—	—
Settlements	216	171	(34)	—	—	—
Transfers out of Level 3 into Level 2	—	46	17	—	—	—
Ending balance	$ (91)	$ (59)	$ (151)	$ 7	$ 6	$ 19

(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):

	2023		2022	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 52,172	$ 48,624	$ 51,635	$ 46,906

(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, 2023 are as follows (in millions):

	2024	2025	2026	2027	2028	2029 and Thereafter	Total
<u>Contract type:</u>							
Fuel, capacity and transmission contract commitments	$ 2,360	$ 1,666	$ 1,351	$ 1,305	$ 1,189	$ 12,055	$ 19,926
Construction commitments	1,883	475	388	67	22	28	2,863
Easements	84	82	82	82	85	3,213	3,628
Maintenance, service and other contracts	482	459	452	323	258	1,325	3,299
	$ 4,809	$ 2,682	$ 2,273	$ 1,777	$ 1,554	$ 16,621	$ 29,716

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, 2023, 2022 and 2021, $109 million, $100 million and $76 million, respectively, were incurred for coal transportation services, the majority of which was related to the BNSF agreement.

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 and construction of wind- and solar-powered generating facilities and the settlement of AROs.
- Nevada Utilities' firm construction commitments consisting of costs associated with a planned 150-MW solar photovoltaic facility with an additional 100 MWs of co-located battery storage that will be developed in Clark County, Nevada, the planned Greenlink Nevada transmission expansion program that will be developed in western and northern Nevada, a planned 444 MWs of peaking combustion turbines that will be developed at the Silverhawk generating facility in Clark County, Nevada, costs associated with one additional solar photovoltaic facility project and certain other generation plant projects. The solar project, pending PUCN approval, is a 400-MW solar photovoltaic facility with an additional 400 MWs of co-located battery storage that would be developed in Churchill County, Nevada.
- AltaLink's investments in directly assigned transmission projects from the AESO.

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 the 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 is intended to resolve disputes surrounding PacifiCorp's efforts to relicense the Klamath Hydroelectric Project. The KHSA establishes a process for PacifiCorp, the states of Oregon and California ("States") and other stakeholders to assess whether dam removal can 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"), who would conduct dam removal; and (4) ability for PacifiCorp to operate the facilities for the benefit of customers until dam removal commences.

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 FERC approved the partial transfer of the Klamath license in a July 2020 order, subject to the condition that PacifiCorp remains co-licensee. Under the amended KHSA, PacifiCorp did not agree to remain co-licensee during the surrender and removal process given concerns about liability protections for PacifiCorp and its customers. In November 2020, PacifiCorp entered a memorandum of agreement (the "MOA") with the KRRC, the Karuk Tribe, the Yurok Tribe and the States to continue implementation of the KHSA. The agreement required the States, PacifiCorp and KRRC to file a new license transfer application to remove PacifiCorp from the license for the Lower Klamath Project and add the States and KRRC as co-licensees for the purposes of surrender. In addition, the MOA provides for additional contingency funding of $45 million, equally split between PacifiCorp and the States, and for PacifiCorp and the States to equally share in any additional cost overruns in the unlikely event that dam removal costs exceed the $450 million in funding to ensure dam removal is complete. The MOA also requires PacifiCorp to cover the costs associated with certain pre-existing environmental conditions. In June 2021, the FERC approved the transfer of the Lower Klamath Project dams from PacifiCorp to the KRRC and the States as co-licensees. In July 2021, the Oregon, Wyoming, Idaho and California state public utility commissions conditionally approved the required property transfer applications. In August 2021, PacifiCorp notified the Public Service Commission of Utah of the property transfer, however no formal approval is required in Utah. In August 2022, the FERC staff issued a final environmental impact statement for the project, concluding that dam removal is the preferred action. In November 2022, the FERC issued a license surrender order for the project, which was accepted by the KRRC and the States in December 2022, along with the transfer of the Lower Klamath Project dams. Although PacifiCorp no longer owns the Lower Klamath Project, PacifiCorp will continue to operate the facilities under an operation and maintenance agreement with the KRRC until each facility is ready for removal. 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) is anticipated to be completed in 2024.

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 $314 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

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.

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.

As of the date of this filing, 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 in Oregon for which two jury verdicts were issued in June 2023 and January 2024 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, the U.S. and Oregon Departments of Justice have informed PacifiCorp that they are contemplating filing actions against PacifiCorp in connection with certain of the Oregon 2020 Wildfires. PacifiCorp is actively cooperating with the U.S. and Oregon Departments of Justice on resolving these alleged claims, including through the pursuit of alternative dispute resolution.

Amounts sought in the complaints and demands filed in Oregon and in certain demands made in California total approximately $8 billion, excluding any doubling or trebling of damages included in the complaints. 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. Based on available information to date, PacifiCorp believes it is probable that losses will be incurred associated with the 2020 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.

The James Case

On September 30, 2020, a class action complaint against PacifiCorp was filed, captioned *Jeanyne James et al. v. PacifiCorp et al*, in Multnomah County Circuit Court, Oregon ("*James*"). 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 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. 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 ordered trial dates for two consolidated jury trials including approximately 10 class members each and a third trial for certain commercial timber plaintiffs wherein plaintiffs in each of the three damages phase trials will present evidence regarding their damages. The first of these trials addressing nine individual plaintiffs was held in January 2024 while the remaining trials are scheduled at various dates through April 2024.

In January 2024, the Multnomah County Circuit Court entered a limited judgment and money award for the June 2023 *James* verdict. The limited judgment awards the aforementioned damages, 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 ORS 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 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. PacifiCorp will request that the Multnomah County Circuit Court judge offset the damage awards by deducting insurance proceeds received by any of the nine plaintiffs. PacifiCorp intends to appeal the jury's damage awards associated with the January 2024 jury verdict once judgement is entered.

2022 McKinney Fire

According to the California Department of Forestry and Fire Protection, on July 29, 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. The cause of the 2022 McKinney Fire is undetermined and remains under investigation by the U.S. Forest Service, the California Public Utilities Commission, PacifiCorp and various experts engaged by PacifiCorp.

As of the date of this filing, multiple complaints have been filed in California on behalf of plaintiffs related to the 2022 McKinney Fire. 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, but the amount of damages sought is not specified.

Based on available information to date, PacifiCorp believes it is probable a loss will be incurred associated with the 2022 McKinney Fire. Final determinations of liability will only be made following the completion of comprehensive investigations, litigation or similar processes.

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 increased its accrual by $1,930 million during the year ended December 31, 2023, bringing its cumulative estimated probable losses associated with the Wildfires to $2,407 million through December 31, 2023. 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, 2023, PacifiCorp paid $684 million in settlements associated with the 2020 Wildfires, including $299 million to 463 claimants and $250 million to 10 companies with commercial timber interests associated with the Archie Creek, French Creek, Susan Creek and Smith Springs Road fires (collectively, the "Archie Creek Complex Fire") in Douglas County, Oregon. The Archie Creek Complex Fire settlements resolve substantially all claims filed by individual plaintiffs and all claims filed by commercial timber plaintiffs associated with the Archie Creek Complex Fire, but do not address related damages claimed by the U.S. or Oregon Departments of Justice. In January 2024 through February 23, 2024, PacifiCorp entered into additional settlements associated with the 2020 Wildfires totaling $51 million with 167 plaintiffs.

The following table presents changes in PacifiCorp's liability for estimated losses associated with the Wildfires for the years ended December 31 (in millions):

	2023	2022	2021
Beginning balance	$ 424	$ 252	$ 252
Accrued losses	1,930	225	—
Payments[(1)]	(631)	(53)	—
Ending balance	$ 1,723	$ 424	$ 252

(1) Amounts represent payments made to settle certain claims associated with the 2020 Wildfires, including $549 million in December 2023 resulting from the above-described settlement agreements reached in December 2023 associated with the Archie Creek Complex Fire.

As of December 31, 2023 and 2022, $4 million and $24 million of PacifiCorp's liability for estimated losses associated with the Wildfires was included in Other current liabilities on the Consolidated Balance Sheets.

Until such time that settlement terms or other conclusions are reached to indicate that payments are expected to occur in the short-term, PacifiCorp's liability for estimated losses associated with the Wildfires is classified as a noncurrent liability captioned Wildfires liabilities on the Consolidated Balance Sheets.

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):

	2023	2022	2021
Beginning balance	$ 246	$ 116	$ 116
Accruals	253	161	—
Payments received	—	(31)	—
Ending balance	$ 499	$ 246	$ 116

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. As of December 31, 2022, the $246 million was included in Other assets on the Consolidated Balance Sheets. In January and February 2024, PacifiCorp received $338 million of insurance proceeds related to the 2020 Wildfires.

During the years ended December 31, 2023, 2022 and 2021, PacifiCorp recognized probable losses net of expected insurance recoveries associated with the Wildfires of $1,677 million, $64 million and $— million, respectively. No additional insurance recoveries beyond those accrued 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, the variation in the types of properties and damages and the ultimate outcome of legal actions.

HomeServices Antitrust Cases

HomeServices is currently defending against eleven antitrust cases, all in federal district courts. In each case, plaintiffs claim HomeServices (or, in one instance, Berkshire Hathaway) and certain of its subsidiaries 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 provided written notice of the damages sought totaling approximately $9 billion by separate 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 (formerly Realogy Holdings Corp.), 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 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. Federal law authorizes trebling of damages and the award of pre-judgment interest and attorney fees. Joint and several liability applies for the co-defendants. Prior to the trial, Anywhere Real Estate (formerly Realogy Holdings Corp.) and RE/MAX, LLC reached settlement agreements with the plaintiffs, which have not yet received final approval from the court. Final judgment has not yet been entered by the U.S. District Court for the Western District of Missouri. 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.

Based on available information to date, HomeServices believes losses are likely to occur as a result of the jury verdict in the Burnett case and that such damages could be up to $5.4 billion, excluding attorneys' fees, prejudgment interest and other costs subject to determination by the court. Under the current circumstances, HomeServices is currently unable to reasonably estimate such loss due to, among other reasons, the joint and several nature of the liability and the early stage of the appeals process; therefore, no loss has been accrued as of the date of this filing. While HomeServices intends to appeal any final judgment, the outcome of such appeals, if adverse, could have a material adverse effect on HomeServices' financial condition.

It is also reasonably possible HomeServices will incur losses from the ten remaining antitrust cases that could have a material adverse effect on HomeServices' financial condition. HomeServices is currently unable to reasonably estimate a specific range of possible losses that could be incurred due to, among other reasons, the lack of information about the size of the plaintiff class and potential damages, as well as the joint and several nature of potential liability of the defendants.

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):

	2023								
	PacifiCorp	MidAmerican Funding	NV Energy	Northern Powergrid	BHE Pipeline Group	BHE Transmission	BHE Renewables[1]	BHE and Other[2]	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[1]	BHE and Other[2]	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

	2021								
	PacifiCorp	MidAmerican Funding	NV Energy	Northern Powergrid	BHE Pipeline Group	BHE Transmission	BHE Renewables[1]	BHE and Other[2]	Total
Customer Revenue:									
Regulated:									
Retail Electric	$ 4,847	$ 2,128	$ 2,828	$ —	$ —	$ —	$ —	$ (2)	$ 9,801
Retail Gas	—	859	115	—	—	—	—	—	974
Wholesale	157	454	62	—	57	—	—	(3)	727
Transmission and distribution	143	58	74	1,023	—	702	—	—	2,000
Interstate pipeline	—	—	—	—	2,404	—	—	(131)	2,273
Other	108	—	1	—	(1)	—	—	1	109
Total Regulated	5,255	3,499	3,080	1,023	2,460	702	—	(135)	15,884
Nonregulated	—	15	3	43	956	35	1,374	(2)	2,424
Total Customer Revenue	5,255	3,514	3,083	1,066	3,416	737	1,374	(137)	18,308
Other revenue	41	33	24	122	128	(6)	287	(2)	627
Total	$ 5,296	$ 3,547	$ 3,107	$ 1,188	$ 3,544	$ 731	$ 1,661	$ (139)	$ 18,935

(1) Effective January 1, 2023, the Company's unregulated retail energy services business was transferred to a subsidiary of BHE Renewables. Prior period amounts, which were previously reported in BHE and Other, have been reclassified to reflect this activity in BHE Renewables.

(2) 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		
	2023	2022	2021
Customer Revenue:			
Brokerage	$ 4,000	$ 4,867	$ 5,498
Franchise	55	66	85
Total Customer Revenue	4,055	4,933	5,583
Mortgage and other revenue	267	335	632
Total	$ 4,322	$ 5,268	$ 6,215

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, 2023, by reportable segment (in millions):

	Performance obligations expected to be satisfied		
	Less than 12 months	More than 12 months	Total
BHE Pipeline Group	$ 2,984	$ 20,019	$ 23,003

(18) BHE Shareholders' Equity

Preferred Stock

As of December 31 2022, BHE had 849,982 shares outstanding of its Perpetual Preferred Stock (the "4% Perpetual Preferred Stock") issued to certain subsidiaries of Berkshire Hathaway Inc. The 4% Perpetual Preferred Stock had a liquidation preference of $1,000 per share and paid a 4.00% dividend per share on the liquidation preference. Dividends accrued and accumulated daily, were cumulative, compounded semi-annually and, if declared, were payable in cash semi-annually in arrears on May 15 and November 15 of each year. If dividends were not declared and paid, any accumulating dividends would continue to accumulate and compound. BHE would 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 should first receive, or simultaneously have received, a dividend in an amount at least equivalent to the amount accumulated and not previously paid. BHE would 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

On March 14, 2000, and as amended on December 7, 2005, BHE's shareholders entered into a Shareholder Agreement that provides specific rights to certain shareholders. One of these rights allows certain shareholders the ability to put their common shares to BHE at the then-current fair value dependent on certain circumstances controlled by BHE.

In June 2022, BHE purchased 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.

Restricted Net Assets

BHE has maximum debt-to-total capitalization percentage restrictions imposed by its senior unsecured credit facilities expiring in June 2026 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 $23.2 billion as of December 31, 2023.

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 $21.8 billion as of December 31, 2023.

(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, 2020	$ (492)	$ (1,062)	$ (8)	$ 10	$ (1,552)
Other comprehensive income (loss)	174	(24)	67	(5)	212
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)

Reclassifications from AOCI to net income for the years ended December 31, 2023, 2022 and 2021 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, 2022, BHE owned an indirect 25% economic interest in Cove Point, consisting of 100% of the general partner interest and 25% of the total limited partner interests. As described in Note 3, on September 1, 2023, BHE completed its acquisition of 50% of the limited partner interest in Cove Point from DEI, and accordingly, owns an aggregate 75% of the limited partner interest and continues to own 100% of the general partner interest of Cove Point. BHE concluded that Cove Point is a VIE due to the limited partners 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, 2023 and 2022, 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):

	2023	2022	2021
Supplemental disclosure of cash flow information:			
Interest paid, net of amounts capitalized	$ 2,109	$ 2,071	$ 2,041
Income taxes received, net[(1)]	$ 1,370	$ 1,863	$ 1,309
Supplemental disclosure of non-cash investing and financing transactions:			
Accruals related to property, plant and equipment additions	$ 1,494	$ 1,049	$ 834

(1) Includes $1,479 million, $1,961 million and $1,441 million of income taxes received from Berkshire Hathaway in 2023, 2022 and 2021, respectively.

(22) Segment Information

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. Effective January 1, 2023, the Company's unregulated retail energy services business was transferred to a subsidiary of BHE Renewables. Prior period amounts, which were previously reported in BHE and Other, have been reclassified to reflect this activity in BHE Renewables. Information related to the Company's reportable segments is shown below (in millions):

	Years Ended December 31,		
	2023	2022	2021
Operating revenue:			
PacifiCorp	$ 5,936	$ 5,679	$ 5,296
MidAmerican Funding	3,393	4,025	3,547
NV Energy	4,523	3,824	3,107
Northern Powergrid	1,303	1,365	1,188
BHE Pipeline Group	3,774	3,844	3,544
BHE Transmission	799	732	731
BHE Renewables	1,710	1,737	1,661
HomeServices	4,322	5,268	6,215
BHE and Other[(1)]	(158)	(137)	(139)
Total operating revenue	$ 25,602	$ 26,337	$ 25,150
Depreciation and amortization:			
PacifiCorp	$ 1,126	$ 1,120	$ 1,088
MidAmerican Funding	908	1,168	914
NV Energy	615	566	549
Northern Powergrid	455	361	305
BHE Pipeline Group	542	508	492
BHE Transmission	256	239	238
BHE Renewables	266	265	242
HomeServices	50	56	52
BHE and Other[(1)]	2	3	1
Total depreciation and amortization	$ 4,220	$ 4,286	$ 3,881

	Years Ended December 31,		
	2023	2022	2021
Operating income:			
PacifiCorp	$ (799)	$ 1,158	$ 1,133
MidAmerican Funding	521	438	416
NV Energy	507	606	621
Northern Powergrid	404	551	543
BHE Pipeline Group	1,699	1,720	1,516
BHE Transmission	332	333	339
BHE Renewables	197	327	344
HomeServices	6	151	505
BHE and Other[1]	(87)	(43)	(90)
Total operating income	2,780	5,241	5,327
Interest expense	(2,415)	(2,216)	(2,118)
Capitalized interest	132	76	64
Allowance for equity funds	267	167	126
Interest and dividend income	412	154	89
Gains (losses) on marketable securities, net	669	(2,002)	1,823
Other, net	116	(7)	(17)
Total income before income tax (benefit) expense and equity loss	$ 1,961	$ 1,413	$ 5,294
Interest expense:			
PacifiCorp	$ 546	$ 431	$ 430
MidAmerican Funding	362	333	319
NV Energy	259	221	206
Northern Powergrid	119	133	130
BHE Pipeline Group	150	148	143
BHE Transmission	150	153	155
BHE Renewables	160	179	161
HomeServices	13	7	4
BHE and Other[1]	656	611	570
Total interest expense	$ 2,415	$ 2,216	$ 2,118
Income tax (benefit) expense:			
PacifiCorp	$ (553)	$ (61)	$ (78)
MidAmerican Funding	(695)	(776)	(680)
NV Energy	41	56	56
Northern Powergrid	122	75	192
BHE Pipeline Group	300	276	269
BHE Transmission	19	14	10
BHE Renewables[2]	(876)	(879)	(750)
HomeServices	5	47	138
BHE and Other[1]	(62)	(668)	(289)
Total income tax (benefit) expense	$ (1,699)	$ (1,916)	$ (1,132)

	Years Ended December 31,		
	2023	2022	2021
Earnings on common shares:			
PacifiCorp	$ (468)	$ 921	$ 889
MidAmerican Funding	980	947	883
NV Energy	394	427	439
Northern Powergrid	165	385	247
BHE Pipeline Group	1,079	1,040	807
BHE Transmission	246	247	247
BHE Renewables[2]	518	643	459
HomeServices	13	100	387
BHE and Other[1]	59	(2,035)	1,311
Total earnings on common shares	$ 2,986	$ 2,675	$ 5,669
Capital expenditures:			
PacifiCorp	$ 3,226	$ 2,166	$ 1,513
MidAmerican Funding	1,833	1,869	1,912
NV Energy	1,797	1,113	749
Northern Powergrid	557	768	742
BHE Pipeline Group	1,294	1,157	1,128
BHE Transmission	206	200	279
BHE Renewables	177	140	227
HomeServices	41	48	42
BHE and Other	17	44	19
Total capital expenditures	$ 9,148	$ 7,505	$ 6,611

	As of December 31,		
	2023	2022	2021
Property, plant and equipment, net:			
PacifiCorp	$ 27,051	$ 24,430	$ 22,914
MidAmerican Funding	21,971	21,092	20,302
NV Energy	12,480	10,993	10,231
Northern Powergrid	8,007	7,445	7,572
BHE Pipeline Group	16,904	16,216	15,692
BHE Transmission	6,273	6,209	6,590
BHE Renewables	6,169	6,236	6,107
HomeServices	187	188	169
BHE and Other	206	234	239
Total property, plant and equipment, net	$ 99,248	$ 93,043	$ 89,816

	As of December 31,		
	2023	2022	2021
Total assets:			
PacifiCorp	$ 33,757	$ 30,559	$ 27,615
MidAmerican Funding	27,331	26,077	25,352
NV Energy	17,788	16,676	15,239
Northern Powergrid	9,596	9,005	9,326
BHE Pipeline Group	21,723	21,005	20,434
BHE Transmission	9,624	9,334	9,476
BHE Renewables	11,045	11,797	12,055
HomeServices	3,407	3,436	4,574
BHE and Other	3,569	5,951	7,994
Total assets	$ 137,840	$ 133,840	$ 132,065

	Years Ended December 31,		
	2023	2022	2021
Operating revenue by country:			
U.S.	$ 23,593	$ 24,263	$ 23,215
United Kingdom	1,277	1,345	1,188
Canada	706	709	719
Australia	20	20	—
Other	6	—	28
Total operating revenue by country	$ 25,602	$ 26,337	$ 25,150
Income before income tax (benefit) expense and equity loss by country:			
U.S.	$ 1,489	$ 771	$ 4,650
United Kingdom	294	447	454
Canada	181	181	181
Australia	(5)	15	(8)
Other	2	(1)	17
Total income before income tax (benefit) expense and equity loss by country	$ 1,961	$ 1,413	$ 5,294

	As of December 31,		
	2023	2022	2021
Property, plant and equipment, net by country:			
U.S.	$ 85,128	$ 79,578	$ 75,774
United Kingdom	7,710	6,959	7,487
Canada	6,178	6,091	6,547
Australia	232	415	8
Total property, plant and equipment, net by country	$ 99,248	$ 93,043	$ 89,816

(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 shows the change in the carrying amount of goodwill by reportable segment for the years ended December 31, 2023 and 2022 (in millions):

	PacifiCorp	MidAmerican Funding	NV Energy	Northern Powergrid	BHE Pipeline Group	BHE Transmission	BHE Renewables	HomeServices	Total
December 31, 2021	$ 1,129	$ 2,102	$ 2,369	$ 992	$ 1,814	$ 1,563	$ 95	$ 1,586	$ 11,650
Acquisitions	—	—	—	—	—	—	—	16	16
Foreign currency translation	—	—	—	(75)	—	(102)	—	—	(177)
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

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 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. The decrease in net income was primarily due to an increase in estimated losses of $1,613 million associated with the 2020 Wildfires and the 2022 McKinney Fire, net of expected insurance recoveries, higher operations and maintenance expense, higher property and other taxes and lower utility margin, 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%.

Net income for the year ended December 31, 2022, was $920 million, an increase of $32 million, or 4%, compared to 2021, primarily due to higher utility margin, lower other expense, including higher allowance for equity and borrowed funds used during construction and lower property and other taxes, partially offset by higher operations and maintenance expense, largely due to higher general and plant maintenance costs and an increase in estimated losses of $64 million associated with the 2020 Wildfires, net of expected insurance recoveries, higher depreciation and amortization expense, and lower income tax benefit. Utility margin increased primarily due to higher net power cost deferrals, higher retail prices and volumes, higher average wholesale prices, lower coal-fueled generation volumes and higher net wheeling revenues, partially offset by higher natural gas-fueled generation prices and volumes, higher purchased electricity costs from higher volumes and prices, higher coal-fueled generation prices, lower wind-based ancillary revenues, and lower wholesale volumes. Retail customer volumes increased 1.6% due to an increase in the average number of customers, favorable impacts of weather and an increase in commercial customer usage, partially offset by a decrease in residential and industrial customer usage. Energy generated decreased 4% for 2022 compared to 2021 primarily due to lower coal-fueled generation, partially offset by higher wind-powered, natural gas-fueled and hydroelectric-powered generation. Wholesale electricity sales volumes decreased 5% and purchased electricity volumes increased 20%.

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 profitability 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 running 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):

	2023	2022	Change		2022	2021	Change	
Utility margin:								
Operating revenue	$ 5,936	$ 5,679	$ 257	5 %	$ 5,679	$ 5,296	$ 383	7 %
Cost of fuel and energy	2,246	1,979	267	13	1,979	1,831	148	8
Utility margin	3,690	3,700	(10)	—	3,700	3,465	235	7
Operations and maintenance	1,469	1,163	306	26	1,163	1,031	132	13
Wildfires losses, net	1,677	64	1,613	*	64	—	64	*
Depreciation and amortization	1,126	1,120	6	1	1,120	1,088	32	3
Property and other taxes	215	195	20	10	195	213	(18)	(8)
Operating income	$ (797)	$ 1,158	$ (1,955)	(169)%	$ 1,158	$ 1,133	$ 25	2 %

* Not meaningful

Utility Margin

A comparison of key operating results related to utility margin is as follows for the years ended December 31:

	2023	2022	Change		2022	2021	Change	
Utility margin (in millions):								
Operating revenue	$ 5,936	$ 5,679	$ 257	5 %	$ 5,679	$ 5,296	$ 383	7 %
Cost of fuel and energy	2,246	1,979	267	13	1,979	1,831	148	8
Utility margin	$ 3,690	$ 3,700	$ (10)	— %	$ 3,700	$ 3,465	$ 235	7 %
Sales (GWhs):								
Residential	18,159	18,425	(266)	(1)%	18,425	17,905	520	3 %
Commercial[(1)]	20,491	19,570	921	5	19,570	18,839	731	4
Industrial[(1)]	16,705	17,622	(917)	(5)	17,622	17,909	(287)	(2)
Other[(1)]	1,341	1,547	(206)	(13)	1,547	1,621	(74)	(5)
Total retail	56,696	57,164	(468)	(1)	57,164	56,274	890	2
Wholesale	2,911	4,836	(1,925)	(40)	4,836	5,113	(277)	(5)
Total sales	59,607	62,000	(2,393)	(4)%	62,000	61,387	613	1 %
Average number of retail customers (in thousands)	2,069	2,037	32	2 %	2,037	2,003	34	2 %
Average revenue per MWh:								
Retail	$ 96.25	$ 89.33	$ 6.92	8 %	$ 89.33	$ 86.08	$ 3.25	4 %
Wholesale	$ 66.04	$ 61.39	$ 4.65	8 %	$ 61.39	$ 37.90	$ 23.49	62 %
Heating degree days	10,415	10,767	(352)	(3)%	10,767	9,914	853	9 %
Cooling degree days	2,183	2,451	(268)	(11)%	2,451	2,431	20	1 %
Sources of energy (GWhs)[(1)]:								
Coal	21,950	28,390	(6,440)	(23)%	28,390	31,566	(3,176)	(10)%
Natural gas	14,050	13,686	364	3	13,686	13,323	363	3
Wind[(2)]	6,500	7,238	(738)	(10)	7,238	6,686	552	8
Hydroelectric and other[(2)]	3,258	3,206	52	2	3,206	3,010	196	7
Total energy generated	45,758	52,520	(6,762)	(13)	52,520	54,585	(2,065)	(4)
Energy purchased	18,404	13,968	4,436	32	13,968	11,601	2,367	20
Total	64,162	66,488	(2,326)	(3)%	66,488	66,186	302	— %
Average cost of energy per MWh:								
Energy generated[(3)]	$ 24.65	$ 22.86	$ 1.79	8 %	$ 22.86	$ 18.05	$ 4.81	27 %
Energy purchased	$ 80.38	$ 71.15	$ 9.23	13 %	$ 71.15	$ 66.93	$ 4.22	6 %

(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, 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.

Wildfires losses, net increased $1,613 million for 2023 compared to 2022 due to an increase in estimated losses associated with the 2020 Wildfires and the 2022 McKinney Fire, net of expected insurance recoveries.

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 decreases 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.

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 values 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 2020 Wildfires and the 2022 McKinney Fire, 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.

<u>Year Ended December 31, 2022 Compared to Year Ended December 31, 2021</u>

Utility margin increased $235 million, or 7% for 2022 compared to 2021 primarily due to:

- $290 million from higher deferred net power costs in accordance with established adjustment mechanisms;
- $263 million of higher retail revenue primarily due to higher average prices and higher volumes. Retail customer volumes increased 1.6% primarily due to an increase in the average number of customers, favorable impacts of weather and an increase in commercial customer usage, partially offset by a decrease in residential and industrial customer usage;
- $103 million of higher wholesale revenue primarily due to higher average prices, partially offset by lower volumes;
- $44 million of lower coal-fueled generation costs due to lower volumes, partially offset by higher average prices; and
- $19 million of favorable wheeling activities.

The increases above were partially offset by:

- $259 million of higher natural gas-fueled generation costs primarily due to higher average prices and higher volumes;
- $217 million of higher purchased electricity costs from higher volumes and prices; and
- $10 million of lower wind-based ancillary revenue.

Wildfires losses, net increased $64 million for 2022 compared to 2021 due to an increase in estimated losses associated with the 2020 Wildfires, net of expected insurance recoveries.

Operations and maintenance increased $132 million, or 13%, for 2022 compared to 2021 primarily due to:

- $38 million of higher plant maintenance costs;
- $37 million of higher consumption of materials, chemical and start-up fuel costs;
- $27 million of higher DSM amortization expense driven by higher spend in Oregon, Utah, Wyoming and Washington (offset in retail revenue);
- $25 million of changes in the prior year in how obligations associated with the implementation of the Klamath Hydroelectric Settlement Agreement will be met; and
- $17 million of higher insurance premiums due to higher cost of third-party liability insurance coverage resulting from the impact of industry-wide catastrophic wildfires.

The increases above were partially offset by:

- $22 million of deferrals of vegetation management costs in Oregon and Utah, net of higher vegetation management and wildfire mitigation costs.

Depreciation and amortization increased $32 million, or 3%, for 2022 compared to 2021 primarily due to higher plant-in-service balances in the current year and prior year deferral of the 2018 depreciation study in Idaho compared to current year amortization, partially offset by current year allocation adjustment for Oregon incremental depreciation of certain coal units and Oregon deferral associated with the depreciation of certain wind-powered generating facilities.

Property and other taxes decreased $18 million, or 8%, for 2022 compared to 2021 primarily due to lower property tax rates in Utah.

Allowance for borrowed and equity funds increased $28 million, or 38%, for 2022 compared to 2021 primarily due to higher qualified construction work-in-progress balances and higher rates.

Interest and dividend income increased $20 million, or 83%, for 2022 compared to 2021 primarily due to the recording of interest on the 2021 Oregon PCAM deferral and higher investment income due to higher average interest rates.

Other, net decreased $23 million for 2022 compared to 2021 primarily due to lower cash surrender value of corporate-owned life insurance policies driven by market declines, unfavorable change in deferred compensation and the long-term incentive plan primarily due to market movements (offset in operations and maintenance expense) and higher pension costs primarily due to lower expected return on net assets.

Income tax benefit decreased $17 million, or 22% for 2022 compared to 2021. The effective tax rate was (7)% and (10)% for 2022 and 2021, respectively. The effective tax rate increased primarily as a result of lower effects of ratemaking associated with excess deferred income tax amortization and an increase to the valuation allowance for state net operating losses, partially offset by increased PTCs from PacifiCorp's wind-powered generating facilities in the current year.

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 would further reduce PacifiCorp's liquidity and availability under its revolving credit facility as described below under "Credit Facility" and "Letters of Credit." 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, 2023, 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, 2023, PacifiCorp's total net liquidity was as follows (in millions):

Cash and cash equivalents	$	138
Credit facility[1]		2,000
Less:		
Short-term debt		(1,604)
Tax-exempt bond support and letters of credit		(249)
Net credit facility		147
Total net liquidity[2]	$	285
Credit facility:		
Maturity date		2026

(1) Refer to Note 7 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K and "Credit Facility" below for further discussion regarding PacifiCorp's credit facilities.

(2) Excludes $900 million of available liquidity under a delayed draw term loan.

Operating Activities

Net cash flows from operating activities for the years ended December 31, 2023 and 2022 were $700 million and $1.82 billion, 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.

Net cash flows from operating activities for the years ended December 31, 2022 and 2021 were $1.82 billion and $1.80 billion, respectively. The increase is primarily due to higher collections from retail customers, collateral received from counterparties, transmission deposits and cash received for income taxes, partially offset by higher fuel, wholesale and material and supplies purchases.

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, 2023 and 2022 were $(3.22) billion and $(2.16) billion, respectively. The increase in net cash outflows from investing activities is mainly due to an increase in capital expenditures of $1.06 billion.

Net cash flows from investing activities for the years ended December 31, 2022 and 2021 were $(2.16) billion and $(1.50) billion, respectively. The increase in net cash outflows from investing activities is mainly due to an increase in capital expenditures of $653 million.

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, 2023, PacifiCorp estimated it would be able to issue up to $7.2 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

Following PacifiCorp's January 2024 First Mortgage Bond issuances, PacifiCorp currently has no remaining regulatory authority from the OPUC and the IPUC to issue additional long-term debt. PacifiCorp must apply for additional issuance authority from the OPUC and IPUC and 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 through September 2026.

PacifiCorp currently has regulatory authority from the OPUC, the WUTC, the IPUC and the FERC to issue $2.0 billion of short-term debt.

While PacifiCorp's current revolving credit facility is unsecured, upon future renewal, PacifiCorp may be required to secure the facility, which could further limit the amount of First Mortgage Bonds PacifiCorp can issue.

The credit facility and term loan 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, 2023, PacifiCorp's debt to total capitalization ratio was 0.55 to 1.0.

As of December 31, 2023, PacifiCorp was in compliance with all financial covenants that affect access to capital.

Short-term Debt

As of December 31, 2023, PacifiCorp had $1.6 billion of short-term debt outstanding at a weighted average rate of 6.16%, which was subsequently repaid in January 2024. As of December 31, 2022, PacifiCorp had no short-term debt outstanding. 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 May 2023, PacifiCorp issued $1.2 billion of its 5.500% First Mortgage Bonds due May 2054. PacifiCorp intends within 24 months of the issuance date, to allocate an amount equal to the net proceeds to finance or refinance, in whole or in part, new or existing investments or expenditures made in one or more eligible projects in alignment with BHE's Green Financing Framework.

In December 2023, PacifiCorp entered into a $900 million unsecured delayed draw term loan facility expiring in June 2025. Amounts borrowed under the facility bear interest at variable rates based on the Secured Overnight Financing Rate or a base rate, at PacifiCorp's option, plus a pricing margin. Subject to regulatory authority to issue long-term debt, PacifiCorp may draw all or none of the unused commitment up to three times through June 2025. As of December 31, 2023, PacifiCorp had no term loans drawn from the facility and currently has no authority to issue additional long-term debt until additional filings occur with the OPUC and the IPUC and are approved as described above.

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.

PacifiCorp made repayments on long-term debt totaling $449 million and $155 million during the years ended December 31, 2023 and 2022, respectively.

Credit Facility

In June 2023, PacifiCorp amended and restated its existing $1.2 billion unsecured credit facility expiring in June 2024. The amendment increased the lender commitment to $2.0 billion and extended the expiration date to June 2026. Additionally, in June 2023, PacifiCorp terminated its existing $800 million 364-day unsecured credit facility expiring in January 2024.

Preferred Stock

As of December 31, 2023 and 2022, PacifiCorp had non-redeemable preferred stock outstanding with an aggregate stated value of $2 million.

Common Shareholder's Equity

In 2023 and 2022, PacifiCorp declared and paid dividends of $300 million and $100 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 or waivers under financing agreements and from regulators, delay or reduce dividends or spending programs, seek additional new equity contributions from its indirect parent company, BHE, 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		
	2021	2022	2023	2024	2025	2026
Wind generation	$ 131	$ 37	$ 755	$ 502	$ 273	$ 137
Electric distribution	554	543	673	718	779	523
Electric transmission	315	1,184	1,189	1,172	1,096	1,314
Solar generation	—	—	2	—	47	61
Electric battery and pumped hydro storage	5	8	4	59	241	308
Wildfire mitigation	64	159	325	374	324	319
Other	444	235	278	752	785	830
Total	$ 1,513	$ 2,166	$ 3,226	$ 3,577	$ 3,545	$ 3,492

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, energy storage, associated transmission, load forecast and resource adequacy. PacifiCorp anticipates that the additional new renewable and carbon free generation and energy storage will be a mixture of owned and contracted resources. PacifiCorp has included estimates for these new renewable and carbon free generation and energy storage resources, conversion of certain coal-fueled units to natural-gas fueled units, energy storage assets and associated transmission assets in its forecast capital expenditures for 2024 through 2026. 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 $735 million for 2023, $23 million for 2022 and $118 million for 2021. PacifiCorp placed in-service 42 MWs at the Foote Creek III and Foote Creek IV wind-powered generating facilities in 2023 and 516 MWs of new wind-powered generating facilities in 2021. Planned spending for the construction of additional wind-powered generating facilities and those at acquired sites totals $478 million in 2024, $238 million in 2025 and $95 million in 2026 and is primarily for the Rock River I, Rock Creek I and Rock Creek II wind-powered generating facilities totaling approximately 640 MWs that are expected to be placed in-service in 2024 through 2025.
- Electric distribution includes both growth projects and operating expenditures. Growth expenditures include spending on new customer connections totaling $264 million in 2023, $182 million in 2022 and $177 million in 2021. Planned spending for new customer connections totals $359 million in 2024, $423 million in 2025 and $224 million in 2026. The remaining investments primarily relate to expenditures for distribution operations.
- Electric transmission includes both growth projects and operating expenditures. Transmission growth investments primarily reflects costs associated with major transmission projects. Expenditures for these projects totaled $799 million for 2023, $944 million for 2022 and $94 million for 2021. Forecast expenditures for major transmission projects include planned costs for the following segments:
  - 416-mile, 500-kV high-voltage transmission line between the Aeolus substation near Medicine Bow, Wyoming and the Clover substation near Mona, Utah;
  - 59-mile, 230-kV high-voltage transmission line between the Windstar substation near Glenrock, Wyoming and the Aeolus substation;
  - 290-mile, 500-kV high-voltage transmission line from the Longhorn substation near Boardman, Oregon to the Hemingway substation near Boise, Idaho;

    - 14-mile, 345-kV high-voltage transmission line between the Oquirrh substation in the Salt Lake Valley and the Terminal substation near the Salt Lake City Airport; and
    - 200-mile, 500-kV high-voltage transmission line between the Anticline substation near Point of Rocks, Wyoming and the Populus substation in Downey, Idaho.

  Planned spending for major transmission segments that are expected to be placed in-service in 2024 through 2031 totals $694 million in 2024, $325 million in 2025 and $504 million in 2026. The remaining investments primarily relate to expenditures for transmission operations, generation interconnection requests and other transmission segments.

- Solar generation includes growth projects that are for planned spending for projects that are expected to be placed in-service beyond 2026.
- Electric battery and pumped hydro storage includes growth projects that are for planned spending on projects that are expected to be placed in-service beyond 2026.
- Wildfire mitigation includes operating expenditures previously included in electric distribution and electric transmission. Expenditures for these items totaled $325 million in 2023, $159 million in 2022 and $64 million in 2021. 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 $179 million in 2023, $155 million in 2022 and $108 million for 2021. Planned information technology spending totals $202 million in 2024, $248 million in 2025 and $271 million in 2026. 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 $9.5 billion on long-term debt, including $496 million due in 2024.

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, 2023, 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, 2023, PacifiCorp would have been required to post $267 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 $2.6 billion and total regulatory liabilities were $2.6 billion as of December 31, 2023. 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, 2023, PacifiCorp recognized a net asset totaling $80 million for the funded status of its defined benefit pension and other postretirement benefit plans. As of December 31, 2023, amounts not yet recognized as a component of net periodic benefit cost included in net regulatory assets and accumulated other comprehensive loss totaled $237 million and $13 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, 2023.

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.

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, 2023 Benefit Obligations:				
Discount rate	$ (26)	$ 28	$ (8)	$ 8
Effect on 2023 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 2017 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, 2023, these amounts were recognized as a net regulatory liability of $1.0 billion and will primarily be included in regulated rates over the estimated useful lives of the related properties.

Wildfire Loss Contingencies

As a result of several wildfires that have occurred in PacifiCorp's service territory and surrounding areas in the western U.S., 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 for each of the wildfires and lawsuits 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. 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 2020 Wildfires and the 2022 McKinney fire.

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.

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.

PacifiCorp maintained compliance with its risk management policy and limit procedures during the year ended December 31, 2023.

The table that follows summarizes PacifiCorp's price risk on commodity contracts accounted for as derivatives, excluding net collateral receivable of $10 million and net collateral payable of $78 million as of December 31, 2023 and 2022, 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 Asset (Liability)	Estimated Fair Value after Hypothetical Change in Price	
		10% increase	10% decrease
As of December 31, 2023:			
Total commodity derivative contracts	$ (76)	$ 13	$ (165)
As of December 31, 2022:			
Total commodity derivative contracts	$ 270	$ 381	$ 159

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, 2023 and 2022, a regulatory liability of $76 million and a regulatory asset of $270 million, respectively, was recorded related to the net derivative liability of $76 million and net derivative asset $270 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, 2023 and 2022, PacifiCorp had long-term variable-rate obligations totaling $218 million 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 long-term variable-rate debt as of December 31, 2023 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 long-term variable-rate obligations approximates fair value as of December 31, 2023 and 2022. While PacifiCorp had $1.6 billion of short-term variable rate debt outstanding as of December 31, 2023, it was repaid in January 2024.

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, 2023, 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.

Item 8. Financial Statements and Supplementary Data

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, 2023 and 2022, 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, 2023, 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, 2023 and 2022, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2023, 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 audit 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 the potential loss or range of potential loss and disclose any material amounts.

Management has recorded estimated liabilities and receivables which represent its best estimate of probable losses and expected insurance recoveries 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 and insurance recoveries. 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 insurance recoveries, and related disclosures for wildfire-related contingencies included the following, among others:

- We evaluated management's judgments related to whether a loss was probable or reasonably possible for the Wildfires by inquiring of management and PacifiCorp's external and internal legal counsel regarding the likelihood 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 management's judgments related to whether certain insurance recoveries were probable of collection by inquiring of management and PacifiCorp's external and internal legal counsel regarding the amounts of insurance recoveries recorded or disclosed. With the assistance of our insurance specialists, we tested certain significant assumptions used in the determination of collectability, including obtaining and reading relevant insurance policies to determine whether the types of insurance claims are included or excluded from coverage. We compared a sample of subsequent insurance recoveries collected to recorded amounts.
- We evaluated whether PacifiCorp's disclosures were appropriate and consistent with the information obtained in our procedures.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 23, 2024

We have served as PacifiCorp's auditor since 2006.

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Amounts in millions)

	As of December 31,	
	2023	**2022**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 138	$ 641
Trade receivables, net	853	825
Other receivables, net	447	72
Inventories	532	474
Derivative contracts	16	184
Regulatory assets	631	275
Prepaid expenses	188	102
Other current assets	182	111
Total current assets	2,987	2,684
Property, plant and equipment, net	27,051	24,430
Regulatory assets	1,942	1,605
Other assets	630	686
Total assets	$ 32,610	$ 29,405

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,	
	2023	**2022**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 1,560	$ 1,049
Accrued interest	152	128
Accrued property, income and other taxes	65	67
Accrued employee expenses	93	86
Short-term debt	1,604	—
Current portion of long-term debt	591	449
Regulatory liabilities	70	96
Other current liabilities	441	271
Total current liabilities	4,576	2,146
Long-term debt	9,819	9,217
Regulatory liabilities	2,540	2,843
Deferred income taxes	3,085	3,152
Wildfires liabilities (Note 14)	1,719	400
Other long-term liabilities	899	906
Total liabilities	22,638	18,664
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	5,501	6,269
Accumulated other comprehensive loss, net	(10)	(9)
Total shareholders' equity	9,972	10,741
Total liabilities and shareholders' equity	$ 32,610	$ 29,405

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,		
	2023	2022	2021
Operating revenue	$ 5,936	$ 5,679	$ 5,296
Operating expenses:			
Cost of fuel and energy	2,246	1,979	1,831
Operations and maintenance	1,469	1,163	1,031
Wildfires losses, net (Note 14)	1,677	64	—
Depreciation and amortization	1,126	1,120	1,088
Property and other taxes	215	195	213
Total operating expenses	6,733	4,521	4,163
Operating (loss) income	(797)	1,158	1,133
Other income (expense):			
Interest expense	(546)	(431)	(430)
Allowance for borrowed funds	70	31	24
Allowance for equity funds	144	71	50
Interest and dividend income	98	44	24
Other, net	10	(15)	8
Total other income (expense)	(224)	(300)	(324)
Income (loss) before income tax expense (benefit)	(1,021)	858	809
Income tax expense (benefit)	(553)	(62)	(79)
Net (loss) income	$ (468)	$ 920	$ 888

The accompanying notes are an integral part of these consolidated financial statements.

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE (LOSS) INCOME
(Amounts in millions)

	Years Ended December 31,		
	2023	**2022**	**2021**
Net (loss) income	$ (468)	$ 920	$ 888
Other comprehensive (loss) income, net of tax —			
Unrecognized amounts on retirement benefits, net of tax of $—, $3 and $1	(1)	8	2
Comprehensive (loss) income	$ (469)	$ 928	$ 890

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, 2020	$ 2	$ —	$ 4,479	$ 4,711	$ (19)	$ 9,173
Net income	—	—	—	888	—	888
Other comprehensive income	—	—	—	—	2	2
Common stock dividends declared	—	—	—	(150)	—	(150)
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

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,		
	2023	**2022**	**2021**
Cash flows from operating activities:			
Net (loss) income	$ (468)	$ 920	$ 888
Adjustments to reconcile net (loss) income to net cash flows from operating activities:			
Depreciation and amortization	1,126	1,120	1,088
Allowance for equity funds	(144)	(71)	(50)
Net power cost deferrals	(760)	(482)	(159)
Amortization of net power cost deferrals	231	100	67
Other changes in regulatory assets and liabilities	(161)	(162)	(97)
Deferred income taxes and amortization of investment tax credits	(224)	157	64
Other, net	11	13	(5)
Changes in other operating assets and liabilities:			
Trade receivables, other receivables and other assets	(38)	(88)	15
Inventories	(58)	—	8
Prepaid expenses	(91)	(46)	2
Derivative collateral, net	(100)	95	19
Accrued property, income and other taxes, net	(40)	(46)	(37)
Accounts payable and other liabilities	370	267	1
Wildfires insurance receivable	(253)	(130)	—
Wildfires liability	1,299	172	—
Net cash flows from operating activities	700	1,819	1,804
Cash flows from investing activities:			
Capital expenditures	(3,226)	(2,166)	(1,513)
Other, net	5	5	12
Net cash flows from investing activities	(3,221)	(2,161)	(1,501)
Cash flows from financing activities:			
Proceeds from long-term debt	1,189	1,087	984
Repayments of long-term debt	(449)	(155)	(870)
Net proceeds from (repayments of) short-term debt	1,604	—	(93)
Dividends paid	(300)	(100)	(150)
Other, net	(5)	(2)	(7)
Net cash flows from financing activities	2,039	830	(136)
Net change in cash and cash equivalents and restricted cash and cash equivalents	(482)	488	167
Cash and cash equivalents and restricted cash and cash equivalents at beginning of period	674	186	19
Cash and cash equivalents and restricted cash and cash equivalents at end of period	$ 192	$ 674	$ 186

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 owns subsidiaries principally engaged in energy businesses. BHE is a consolidated 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, 2023 and 2022 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,	
	2023	2022
Cash and cash equivalents	$ 138	$ 641
Restricted cash included in other current assets	51	7
Restricted cash included in other assets	3	26
Total cash and cash equivalents and restricted cash and cash equivalents	$ 192	$ 674

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, 2023 and 2022, 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 change 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):

	2023	2022	2021
Beginning balance	$ 19	$ 18	$ 17
Charged to operating costs and expenses, net	34	18	13
Write-offs, net	(23)	(17)	(12)
Ending balance	$ 30	$ 19	$ 18

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. 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 generating facilities. 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, 2023 and 2022, trade receivables, net on the Consolidated Balance Sheets relate substantially to Customer Revenue, including unbilled revenue of $296 million and $301 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 on the Consolidated Statements of Operations.

Segment Information

PacifiCorp currently has one segment, which includes its regulated electric utility operations.

New Accounting Pronouncements

In November 2023, the FASB issued 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 is currently evaluating the impact of adopting this guidance on its 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.

(3) Property, Plant and Equipment, Net

Property, plant and equipment, net consists of the following as of December 31 (in millions):

	Depreciable Life	2023	2022
Utility Plant:			
Generation	15 - 59 years	$ 13,904	$ 13,726
Transmission	60 - 90 years	8,216	8,051
Distribution	20 - 75 years	9,060	8,477
Intangible plant[1] and other	5 - 75 years	2,833	2,755
Utility plant in-service		34,013	33,009
Accumulated depreciation and amortization		(11,725)	(11,093)
Utility plant in-service, net		22,288	21,916
Nonregulated, net of accumulated depreciation and amortization	14 - 95 years	18	18
		22,306	21,934
Construction work-in-progress		4,745	2,496
Property, plant and equipment, net		$ 27,051	$ 24,430

(1) Computer software costs included in intangible plant are initially assigned a depreciable life of 5 to 10 years.

The average depreciation and amortization rate applied to depreciable property, plant and equipment was 3.4%, 3.5% and 3.5% for the years ended December 31, 2023, 2022 and 2021, 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, 2023 and 2022, and accumulated depreciation of $145 million and $144 million as of December 31, 2023 and 2022, respectively.

(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, 2023 (dollars in millions):

	PacifiCorp Share	Facility in Service	Accumulated Depreciation and Amortization	Construction Work-in-Progress
Jim Bridger Nos. 1 - 4	67 %	$ 1,596	$ 996	$ 26
Hunter No. 1	94	510	237	4
Hunter No. 2	60	316	151	2
Wyodak	80	491	285	—
Colstrip Nos. 3 and 4	10	262	199	—
Hermiston	50	191	111	3
Craig Nos. 1 and 2	19	372	341	—
Hayden No. 1	25	77	55	—
Hayden No. 2	13	45	32	—
Transmission and distribution facilities	Various	900	283	192
Total		$ 4,760	$ 2,690	$ 227

(5) Leases

The following table summarizes PacifiCorp's leases recorded on the Consolidated Balance Sheets as of December 31 (in millions):

	2023	2022
Right-of-use assets:		
Operating leases	$ 12	$ 11
Finance leases	10	9
Total right-of-use assets	$ 22	$ 20
Lease liabilities:		
Operating leases	$ 12	$ 11
Finance leases	12	11
Total lease liabilities	$ 24	$ 22

The following table summarizes PacifiCorp's lease costs for the years ended December 31 (in millions):

	2023	2022	2021
Variable	$ 57	$ 61	$ 56
Operating	4	3	3
Finance:			
Amortization	1	1	5
Interest	1	1	2
Short-term	6	5	3
Total lease costs	$ 69	$ 71	$ 69
Weighted-average remaining lease term (years):			
Operating leases	12.3	11.4	12.7
Finance leases	8.8	9.7	10.1
Weighted-average discount rate:			
Operating leases	3.8 %	3.9 %	3.7 %
Finance leases	10.6 %	11.4 %	11.1 %

Cash payments associated with operating and finance lease liabilities approximated lease cost for the years ended December 31, 2023, 2022 and 2021.

PacifiCorp has the following remaining lease commitments as of December 31, 2023 (in millions):

	Operating	Finance	Total
2024	$ 3	$ 2	$ 5
2025	2	2	4
2026	2	2	4
2027	1	2	3
2028	1	2	3
Thereafter	7	8	15
Total undiscounted lease payments	16	18	34
Less - amounts representing interest	(4)	(6)	(10)
Lease liabilities	$ 12	$ 12	$ 24

(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	2023	2022
Employee benefit plans[1]	16 years	$ 279	$ 290
Utah mine disposition[2]	Various	79	115
Deferred net power costs	2 years	1,117	546
Unrealized loss on derivative contracts	1 year	76	—
Environmental costs	30 years	139	111
Asset retirement obligation	28 years	300	275
Demand side management (DSM)	10 years	245	224
Wildfire mitigation and vegetation management costs	Various	114	111
Other	Various	224	208
Total regulatory assets		$ 2,573	$ 1,880
Reflected as:			
Current assets		$ 631	$ 275
Noncurrent assets		1,942	1,605
Total regulatory assets		$ 2,573	$ 1,880

(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.

PacifiCorp had regulatory assets not earning a return on investment of $1,852 million and $1,200 million as of December 31, 2023 and 2022, respectively.

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	2023	2022
Cost of removal[(1)]	26 years	$ 1,456	$ 1,332
Deferred income taxes[(2)]	Various	1,006	1,164
Unrealized gain on regulated derivatives	N/A	—	270
Other	Various	148	173
Total regulatory liabilities		$ 2,610	$ 2,939
Reflected as:			
Current liabilities		$ 70	$ 96
Noncurrent liabilities		2,540	2,843
Total regulatory liabilities		$ 2,610	$ 2,939

(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 2026 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 letters of credit, has a variable interest rate based on the Secured Overnight Financing Rate 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):

2023:	
Credit facility	$ 2,000
Less:	
Short-term debt	(1,604)
Tax-exempt bond support and letters of credit	(249)
Net credit facility	$ 147
2022:	
Credit facility	$ 1,200
Less:	
Tax-exempt bond support and letters of credit	(249)
Net credit facility	$ 951

As of December 31, 2023, PacifiCorp was in compliance with all financial covenants that affect access to capital.

As of December 31, 2023, PacifiCorp had $1.6 billion of short-term debt outstanding at a weighted average rate of 6.16%, which was subsequently repaid in January 2024. As of December 31, 2022, PacifiCorp had no short-term debt outstanding.

The credit facility and the delayed draw term loan facility described in Note 8 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, 2023, PacifiCorp's debt to total capitalization ratio was 0.55 to 1.0. Refer to Note 8 for discussion of PacifiCorp's January 2024 issuance of First Mortgage Bonds.

As of December 31, 2023, PacifiCorp had $255 million of letter of credit capacity under its $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.

As of December 31, 2022, PacifiCorp had $219 million of letter of credit capacity under the $1.2 billion revolving credit facility that was in place at that time, of which $31 million was outstanding and was utilized as a standby letter of credit, and $7 million of letters of credit outstanding under committed arrangements outside of the facility 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):

	2023			2022	
	Principal Amount	**Carrying Value**	**Average Interest Rate**	**Carrying Value**	**Average Interest Rate**
First mortgage bonds:					
2.95% to 8.23%, due through 2026	$ 775	$ 774	3.92 %	$ 1,223	4.07 %
2.70% to 7.70%, due 2029 to 2031	1,100	1,096	4.35	1,095	4.35
5.25% to 6.35%, due 2034 to 2038	2,350	2,341	5.96	2,340	5.96
4.10% to 6.00%, due 2039 to 2042	950	942	5.40	941	5.40
2.90% to 5.50%, due 2049 to 2054	5,100	5,039	4.38	3,849	4.03
Variable-rate series, tax-exempt bond obligations (2023-4.60% to 5.60%; 2022-3.75% to 4.10%):					
Due 2025	25	25	4.60	25	4.10
Due 2024 to 2025(1)	193	193	5.51	193	3.81
Total long-term debt	$ 10,493	$ 10,410		$ 9,666	

Reflected as:

	2023	2022
Current portion of long-term debt	$ 591	$ 449
Long-term debt	9,819	9,217
Total long-term debt	$ 10,410	$ 9,666

(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 May 2023, PacifiCorp issued $1.2 billion of its 5.50% First Mortgage Bonds due May 2054. PacifiCorp intends within 24 months of the issuance date, to allocate an amount equal to the net proceeds to finance or refinance, in whole or in part, new or existing investments or expenditures made in one or more eligible projects in alignment with BHE's Green Financing Framework.

In December 2023, PacifiCorp entered into a $900 million unsecured delayed draw term loan facility expiring in June 2025. Amounts borrowed under the facility bear interest at variable rates based on the Secured Overnight Financing Rate or a base rate, at PacifiCorp's option, plus a pricing margin. Subject to regulatory authority to issue long-term debt, PacifiCorp may draw all or none of the unused commitment up to three times through June 2025. As of December 31, 2023, PacifiCorp had no term loans drawn from the facility and currently has no authority to issue additional long-term debt until additional filings occur with the Oregon Public Utility Commission ("OPUC") and the Idaho Public Utilities Commission ("IPUC") and are approved as described below. As described in Note 7, the delayed draw term loan facility requires certain ratios to be maintained.

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.

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.

Following PacifiCorp's January 2024 First Mortgage Bond issuances, PacifiCorp currently has no remaining regulatory authority from the OPUC and the IPUC to issue additional long-term debt. PacifiCorp must apply for additional issuance authority from the OPUC and IPUC and 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 through September 2026.

The issuance of PacifiCorp's first mortgage bonds is limited by available property, earnings tests and other provisions of PacifiCorp's mortgage. Approximately $36 billion of PacifiCorp's eligible property (based on original cost) was subject to the lien of the mortgage as of December 31, 2023.

As of December 31, 2023, the annual principal maturities of long-term debt for 2024 and thereafter are as follows (in millions):

		Long-term Debt
2024	$	591
2025		302
2026		100
2027		—
2028		—
Thereafter		9,500
Total		10,493
Unamortized discount and debt issuance costs		(83)
Total	$	10,410

(9) Income Taxes

The effective tax rate for the year ended December 31, 2023, is 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 is 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.

Income tax expense (benefit) consists of the following for the years ended December 31 (in millions):

	2023	2022	2021
Current:			
Federal	$ (324)	$ (216)	$ (150)
State	(5)	(3)	7
Total	(329)	(219)	(143)
Deferred:			
Federal	(172)	90	26
State	(51)	71	40
Total	(223)	161	66
Investment tax credits	(1)	(4)	(2)
Total income tax expense (benefit)	$ (553)	$ (62)	$ (79)

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:

	2023	2022	2021
Federal statutory income tax rate	21 %	21 %	21 %
State income taxes, net of federal income tax benefit	4	3	3
Effects of ratemaking[(1)]	11	(12)	(14)
Federal income tax credits	18	(22)	(20)
Valuation allowance	1	2	—
Other	(1)	1	—
Effective income tax rate	54 %	(7)%	(10)%

(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, 2023, 2022 and 2021 totaled $180 million, $185 million and $164 million, respectively.

The net deferred income tax liability consists of the following as of December 31 (in millions):

	2023	2022
Deferred income tax assets:		
Regulatory liabilities	$ 643	$ 724
Employee benefits	51	59
State carryforwards	84	73
Loss contingencies	429	107
AROs	85	79
Other	117	80
Total deferred income tax assets	1,409	1,122
Valuation allowances	(24)	(35)
Total deferred income tax assets, net	1,385	1,087
Deferred income tax liabilities:		
Property-related items	(3,704)	(3,612)
Regulatory assets	(632)	(462)
Other	(134)	(165)
Total deferred income tax liabilities	(4,470)	(4,239)
Net deferred income tax liability	$ (3,085)	$ (3,152)

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, 2023 (in millions):

	State
Net operating loss carryforwards	$ 1,427
Deferred income taxes on net operating loss carryforwards	$ 64
Expiration dates	2026 - indefinite
Tax credit carryforwards	$ 20
Expiration dates	2024 - 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, 2019, 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 and 2021 as a result of the amount of lump sum distributions in the Retirement Plan exceeding the service and interest cost threshold. The 2021 pension settlement accounting included an interim July 31, 2021 remeasurement of the pension plan assets and projected benefit obligation. As a result of the settlement accounting, PacifiCorp recognized settlement losses of $6 million, net of regulatory deferrals during each of the years ended December 31, 2022 and 2021.

Net Periodic Benefit Cost

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 cost (credit) for the plans included the following components for the years ended December 31 (in millions):

	Pension			Other Postretirement		
	2023	2022	2021	2023	2022	2021
Service cost	$ —	$ —	$ —	$ 1	$ 2	$ 2
Interest cost	39	29	29	11	8	7
Expected return on plan assets	(49)	(42)	(51)	(13)	(11)	(9)
Settlement[1]	—	6	6	—	—	—
Net amortization	12	16	21	(2)	1	1
Net periodic benefit cost (credit)	$ 2	$ 9	$ 5	$ (3)	$ —	$ 1

(1) Pension amounts represent settlement losses of $— million, $24 million and $15 million net of deferrals of $— million, $18 million and $9 million during the years ended December 31, 2023, 2022 and 2021.

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	
	2023	2022	2023	2022
Plan assets at fair value, beginning of year	$ 758	$ 1,058	$ 264	$ 324
Employer contributions[1]	4	4	—	—
Participant contributions	—	—	4	5
Actual (loss) return on plan assets	73	(172)	25	(42)
Settlement[2]	—	(67)	—	—
Benefits paid	(71)	(65)	(22)	(23)
Plan assets at fair value, end of year	$ 764	$ 758	$ 271	$ 264

(1) Pension amounts represent employer contributions to the SERP.

(2) Benefits paid in the form of lump sum distributions that gave rise to the settlement accounting described above.

The following table is a reconciliation of the benefit obligations for the years ended December 31 (in millions):

	Pension		Other Postretirement	
	2023	2022	2023	2022
Benefit obligation, beginning of year	$ 746	$ 1,048	$ 219	$ 288
Service cost	—	—	1	2
Interest cost	39	29	11	8
Participant contributions	—	—	4	5
Actuarial gain (loss)	26	(199)	2	(61)
Settlement[1]	—	(67)	—	—
Benefits paid	(71)	(65)	(22)	(23)
Benefit obligation, end of year	$ 740	$ 746	$ 215	$ 219
Accumulated benefit obligation, end of year	$ 740	$ 746		

(1) Benefits paid in the form of lump sum distributions that gave rise to the settlement accounting described above.

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	
	2023	2022	2023	2022
Plan assets at fair value, end of year	$ 764	$ 758	$ 271	$ 264
Less - Benefit obligation, end of year	740	746	215	219
Funded status	$ 24	$ 12	$ 56	$ 45
Amounts recognized on the Consolidated Balance Sheets:				
Other assets	$ 65	$ 53	$ 56	$ 45
Accrued employee expenses	(4)	(4)	—	—
Other long-term liabilities	(37)	(37)	—	—
Amounts recognized	$ 24	$ 12	$ 56	$ 45

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 $68 million and $61 million as of December 31, 2023 and 2022, 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, 2023 and 2022, respectively, on the Consolidated Balance Sheets. The projected and accumulated benefit obligations for the SERP were $41 million and $42 million at December 31, 2023 and 2022, respectively.

As of December 31, 2023, 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	
	2023	**2022**	**2023**	**2022**
Net loss (gain)	$ 270	$ 273	$ (42)	$ (36)
Regulatory deferrals[1]	22	29	—	1
Total	$ 292	$ 302	$ (42)	$ (35)

(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, 2023 and 2022 is as follows (in millions):

	Regulatory Asset	Accumulated Other Comprehensive Loss	Total
Pension			
Balance, December 31, 2021	$ 286	$ 23	$ 309
Net gain arising during the year	24	(9)	15
Net amortization	(14)	(2)	(16)
Settlement	(6)	—	(6)
Total	4	(11)	(7)
Balance, December 31, 2022	290	12	302
Net loss (gain) arising during the year	—	2	2
Net amortization	(11)	(1)	(12)
Total	(11)	1	(10)
Balance, December 31, 2023	$ 279	$ 13	$ 292

	Regulatory Liability
Other Postretirement	
Balance, December 31, 2021	$ (26)
Net gain arising during the year	(8)
Net amortization	(1)
Total	(9)
Balance, December 31, 2022	(35)
Net gain arising during the year	(9)
Net amortization	2
Total	(7)
Balance, December 31, 2023	$ (42)

Plan Assumptions

Assumptions used to determine benefit obligations and net periodic benefit cost were as follows:

	Pension			Other Postretirement		
	2023	2022	2021	2023	2022	2021
Benefit obligations as of December 31:						
Discount rate	5.20 %	5.55 %	2.90 %	5.20 %	5.50 %	2.90 %
Interest crediting rates for cash balance plan - non-union						
2021	N/A	N/A	0.82 %	N/A	N/A	N/A
2022	N/A	0.88 %	0.88 %	N/A	N/A	N/A
2023	4.73 %	4.73 %	0.88 %	N/A	N/A	N/A
2024	5.98 %	4.73 %	1.90 %	N/A	N/A	N/A
2025	5.98 %	2.60 %	1.90 %	N/A	N/A	N/A
2026 and beyond	3.10 %	2.60 %	1.90 %	N/A	N/A	N/A
Interest crediting rates for cash balance plan - union						
2021	N/A	N/A	1.42 %	N/A	N/A	N/A
2022	N/A	1.94 %	1.94 %	N/A	N/A	N/A
2023	3.55 %	3.55 %	1.94 %	N/A	N/A	N/A
2024	4.47 %	3.55 %	2.30 %	N/A	N/A	N/A
2025	4.47 %	2.40 %	2.30 %	N/A	N/A	N/A
2026 and beyond	2.70 %	2.40 %	2.30 %	N/A	N/A	N/A
Net periodic benefit cost for the years ended December 31:						
Discount rate	5.55 %	2.90 %	2.50 %	5.50 %	2.90 %	2.50 %
Expected return on plan assets	6.00	4.70	6.00	4.78	3.44	2.90

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 2024. 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 2024 through 2028 and for the five years thereafter are summarized below (in millions):

	Projected Benefit Payments	
	Pension	Other Postretirement
2024	$ 76	$ 22
2025	72	22
2026	70	21
2027	66	20
2028	63	19
2029-2033	273	81

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.

In 2020, the assets of the PacifiCorp Master Retirement Trust were transferred into the BHE Master Retirement Trust.

The target allocations (percentage of plan assets) for PacifiCorp's pension and other postretirement benefit plan assets are as follows as of December 31, 2023:

	Pension(1)	Other Postretirement(1)
	%	%
Debt securities(2)	73	79
Equity securities(2)	22	21
Other	5	0

(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, 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	$ 105	$ 323	$ —	$ 428
Investment funds[(2)] measured at net asset value				310
Limited partnership interests[(3)] measured at net asset value				26
Investments at fair value				$ 764
As of December 31, 2022:				
Cash equivalents	$ —	$ 10	$ —	$ 10
Debt securities:				
U.S. government obligations	41	—	—	41
Corporate obligations	—	211	—	211
Municipal obligations	—	15	—	15
Agency, asset and mortgage-backed obligations	—	34	—	34
Equity securities:				
U.S. companies	69	—	—	69
Total assets in the fair value hierarchy	$ 110	$ 270	$ —	$ 380
Investment funds[(2)] measured at net asset value				346
Limited partnership interests[(3)] measured at net asset value				32
Investments at fair value				$ 758

(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 41% and 59%, respectively, for 2023 and 50% and 50%, respectively, for 2022, and are invested in U.S. and international securities of approximately 88% and 12%, respectively, for 2023 and 90% and 10%, respectively, for 2022.

(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, 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	$ 21	$ 117	$ —	138
Investment funds[2] measured at net asset value				133
Investments at fair value				$ 271
As of December 31, 2022:				
Cash and cash equivalents	$ 5	$ 5	$ —	$ 10
Debt securities:				
U.S. government obligations	6	—	—	6
Corporate obligations	—	49	—	49
Municipal obligations	—	13	—	13
Agency, asset and mortgage-backed obligations	—	47	—	47
Equity securities:				
U.S. companies	7	—	—	7
Total assets in the fair value hierarchy	$ 18	$ 114	$ —	132
Investment funds[2] measured at net asset value				132
Investments at fair value				$ 264

(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 38% and 62%, respectively, for 2023 and 41% and 59%, respectively, for 2022, and are invested in U.S. and international securities of approximately 89% and 11%, respectively, for 2023 and 91% and 9%, respectively, for 2022.

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 UMWA labor settlement, PacifiCorp's subsidiary, Energy West Mining Company, triggered involuntary withdrawal from the UMWA 1974 Pension Plan in June 2015 when the UMWA 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):

		PPA of 2006 zone status or plan funded status percentage for plan years beginning July 1,					Contributions			
Plan name	Employer Identification Number	2023	2022	2021	Funding improvement plan	Surcharge imposed under PPA of 2006	2023	2022	2021	Year contributions to plan exceeded more than 5% of total contributions
Local 57 Trust Fund	87-0640888	At least 80%	At least 80%	At least 80%	None	None	$ 5	$ 6	$ 6	2023, 2022, 2021

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 that were due to expire in 2023 were extended to 2028 in December 2022.

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, 2023, 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 $48 million, $44 million and $40 million for the years ended December 31, 2023, 2022 and 2021, 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. Cost of removal regulatory liabilities totaled $1,456 million and $1,332 million as of December 31, 2023 and 2022, respectively.

The following table reconciles the beginning and ending balances of PacifiCorp's ARO liabilities for the years ended December 31 (in millions):

	2023	2022
Beginning balance	$ 331	$ 304
Change in estimated costs	(4)	20
Additions	27	3
Retirements	(9)	(6)
Accretion	11	10
Ending balance	$ 356	$ 331
Reflected as:		
Other current liabilities	$ 9	$ 11
Other long-term liabilities	347	320
	$ 356	$ 331

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.

(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, 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 receivable	(2)	—	12	—	10
Total derivatives - net basis	$ 16	$ 2	$ (64)	$ (20)	$ (66)
As of December 31, 2022:					
Not designated as hedging contracts(1):					
Commodity assets	$ 279	$ 27	$ 9	$ 3	$ 318
Commodity liabilities	(22)	(7)	(14)	(5)	(48)
Total	257	20	(5)	(2)	270
Total derivatives	257	20	(5)	(2)	270
Cash collateral payable(2)	(73)	(5)	—	—	(78)
Total derivatives - net basis	$ 184	$ 15	$ (5)	$ (2)	$ 192

(1) PacifiCorp's commodity derivatives are generally included in rates. As of December 31, 2023 a regulatory asset of $76 million was recorded related to the net derivative liability of $76 million. As of December 31, 2022 regulatory liability of $270 million was recorded related to the net derivative asset of $270 million.

(2) As of December 31, 2022, PacifiCorp had an additional $12 million cash collateral payable that was not required to be netted against total derivatives.

The following table reconciles the beginning and ending balances of PacifiCorp's net regulatory (liabilities) assets and summarizes the pre-tax gains and losses on commodity derivative contracts recognized in net regulatory (liabilities) assets, as well as amounts reclassified to earnings for the years ended December 31 (in millions):

	2023	2022	2021
Beginning balance	$ (270)	$ (53)	$ 17
Changes in fair value recognized in regulatory (liabilities) assets	206	(513)	(171)
Net (losses) gains reclassified to operating revenue	(8)	(13)	(23)
Net gains (losses) reclassified to cost of fuel and energy	148	309	124
Ending balance	$ 76	$ (270)	$ (53)

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	2023	2022
Electricity purchases, net	Megawatt hours	2	2
Natural gas purchases	Decatherms	153	127

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, 2023, 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 $108 million and $48 million as of December 31, 2023 and 2022, respectively, for which PacifiCorp had posted collateral of $12 million and $— 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, 2023 and 2022, PacifiCorp would have been required to post $84 million and $3 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
As of December 31, 2023:					
Assets:					
Commodity derivatives	$ —	$ 32	$ —	$ (14)	$ 18
Money market mutual funds	175	—	—	—	175
Investment funds	26	—	—	—	26
	$ 201	$ 32	$ —	$ (14)	$ 219
Liabilities - Commodity derivatives	$ —	$ (108)	$ —	$ 24	$ (84)
As of December 31, 2022:					
Assets:					
Commodity derivatives	$ —	$ 318	$ —	$ (119)	$ 199
Money market mutual funds	649	—	—	—	649
Investment funds	23	—	—	—	23
	$ 672	$ 318	$ —	$ (119)	$ 871
Liabilities - Commodity derivatives	$ —	$ (48)	$ —	$ 41	$ (7)

(1) Represents netting under master netting arrangements and a net cash collateral receivable of $10 million and a net cash collateral payable of $78 million as of December 31, 2023 and 2022, respectively. As of December 31, 2022, PacifiCorp had an additional $12 million cash collateral payable that was not required to be netted against total derivatives.

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):

	2023		2022	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 10,410	$ 9,722	$ 9,666	$ 9,045

(14) Commitments and Contingencies

Commitments

PacifiCorp has the following firm commitments that are not reflected on the Consolidated Balance Sheet. Certain commitments are with related parties. Refer to Note 21 for transactions associated with these related party contracts. Minimum payments as of December 31, 2023 are as follows (in millions):

	2024	2025	2026	2027	2028	2029 and Thereafter	Total
Contract type:							
Purchased electricity contracts - commercially operable	$ 482	$ 198	$ 196	$ 195	$ 198	$ 1,964	$ 3,233
Purchased electricity contracts - non-commercially operable	—	34	58	58	58	946	1,154
Fuel contracts	673	425	160	169	156	323	1,906
Construction commitments	891	183	5	2	1	—	1,082
Transmission	105	100	92	80	75	394	846
Easements	13	13	13	13	14	797	863
Maintenance, service and other contracts	143	117	128	63	54	240	745
Total commitments	$ 2,307	$ 1,070	$ 652	$ 580	$ 556	$ 4,664	$ 9,829

Purchased Electricity Contracts - Commercially Operable

The table above reflects purchased electricity contracts with expiration dates ranging from 2024 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 or wind-powered generating facilities that 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 10 to 30 years in duration, with certain of the PPAs extending through 2046. 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 2023, 2022 and 2021 energy sources.

Purchased Electricity Contracts - Non-Commercially Operable

PacifiCorp has many long-term PPAs with facilities that have not yet achieved commercial operation, primarily related to wind-powered and solar-powered generated facilities and including with facilities that 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 10 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. In January and February 2024, PacifiCorp entered into new and amended coal supply agreements aggregating approximately $1.9 billion of additional commitments through 2030.

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 is intended to resolve disputes surrounding PacifiCorp's efforts to relicense the Klamath Hydroelectric Project. The KHSA establishes a process for PacifiCorp, the states of Oregon and California ("States") and other stakeholders to assess whether dam removal can 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"), who would conduct dam removal; and (4) ability for PacifiCorp to operate the facilities for the benefit of customers until dam removal commences.

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 FERC approved the partial transfer of the Klamath license in a July 2020 order, subject to the condition that PacifiCorp remains co-licensee. Under the amended KHSA, PacifiCorp did not agree to remain co-licensee during the surrender and removal process given concerns about liability protections for PacifiCorp and its customers. In November 2020, PacifiCorp entered a memorandum of agreement (the "MOA") with the KRRC, the Karuk Tribe, the Yurok Tribe and the States to continue implementation of the KHSA. The agreement required the States, PacifiCorp and KRRC to file a new license transfer application to remove PacifiCorp from the license for the Lower Klamath Project and add the States and KRRC as co-licensees for the purposes of surrender. In addition, the MOA provides for additional contingency funding of $45 million, equally split between PacifiCorp and the States, and for PacifiCorp and the States to equally share in any additional cost overruns in the unlikely event that dam removal costs exceed the $450 million in funding to ensure dam removal is complete. The MOA also requires PacifiCorp to cover the costs associated with certain pre-existing environmental conditions. In June 2021, the FERC approved the transfer of the Lower Klamath Project dams from PacifiCorp to the KRRC and the States as co-licensees. In July 2021, the Oregon, Wyoming, Idaho and California state public utility commissions conditionally approved the required property transfer applications. In August 2021, PacifiCorp notified the Public Service Commission of Utah of the property transfer, however no formal approval is required in Utah. In August 2022, the FERC staff issued a final environmental impact statement for the project, concluding that dam removal is the preferred action. In November 2022, the FERC issued a license surrender order for the project, which was accepted by the KRRC and the States in December 2022, along with the transfer of the Lower Klamath Project dams. Although PacifiCorp no longer owns the Lower Klamath Project, PacifiCorp will continue to operate the facilities under an operation and maintenance agreement with the KRRC until each facility is ready for removal. 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) is anticipated to be completed in 2024.

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 $314 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

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.

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.

As of the date of this filing, 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 in Oregon for which two jury verdicts were issued in June 2023 and January 2024 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, the U.S. and Oregon Departments of Justice have informed PacifiCorp that they are contemplating filing actions against PacifiCorp in connection with certain of the Oregon 2020 Wildfires. PacifiCorp is actively cooperating with the U.S. and Oregon Departments of Justice on resolving these alleged claims, including through the pursuit of alternative dispute resolution.

Amounts sought in the complaints and demands filed in Oregon and in certain demands made in California total approximately $8 billion, excluding any doubling or trebling of damages included in the complaints. 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. Based on available information to date, PacifiCorp believes it is probable that losses will be incurred associated with the 2020 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.

The James Case

On September 30, 2020, a class action complaint against PacifiCorp was filed, captioned *Jeanyne James et al. v. PacifiCorp et al*, in Multnomah County Circuit Court, Oregon ("*James*"). 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 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. 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 ordered trial dates for two consolidated jury trials including approximately 10 class members each and a third trial for certain commercial timber plaintiffs wherein plaintiffs in each of the three damages phase trials will present evidence regarding their damages. The first of these trials addressing nine individual plaintiffs was held in January 2024 while the remaining trials are scheduled at various dates through April 2024.

In January 2024, the Multnomah County Circuit Court entered a limited judgment and money award for the June 2023 *James* verdict. The limited judgment awards the aforementioned damages, 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 ORS 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 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. PacifiCorp will request that the Multnomah County Circuit Court judge offset the damage awards by deducting insurance proceeds received by any of the nine plaintiffs. PacifiCorp intends to appeal the jury's damage awards associated with the January 2024 jury verdict once judgement is entered.

2022 McKinney Fire

According to the California Department of Forestry and Fire Protection, on July 29, 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. The cause of the 2022 McKinney Fire is undetermined and remains under investigation by the U.S. Forest Service, the California Public Utilities Commission, PacifiCorp and various experts engaged by PacifiCorp.

As of the date of this filing, multiple complaints have been filed in California on behalf of plaintiffs related to the 2022 McKinney Fire. 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, but the amount of damages sought is not specified.

Based on available information to date, PacifiCorp believes it is probable a loss will be incurred associated with the 2022 McKinney Fire. Final determinations of liability will only be made following the completion of comprehensive investigations, litigation or similar processes.

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 increased its accrual by $1,930 million during the year ended December 31, 2023, bringing its cumulative estimated probable losses associated with the Wildfires to $2,407 million through December 31, 2023. 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, 2023, PacifiCorp paid $684 million in settlements associated with the 2020 Wildfires, including $299 million to 463 claimants and $250 million to 10 companies with commercial timber interests associated with the Archie Creek, French Creek, Susan Creek and Smith Springs Road fires (collectively, the "Archie Creek Complex Fire") in Douglas County, Oregon. The Archie Creek Complex Fire settlements resolve substantially all claims filed by individual plaintiffs and all claims filed by commercial timber plaintiffs associated with the Archie Creek Complex Fire, but do not address related damages claimed by the U.S. or Oregon Departments of Justice. In January 2024 through February 23, 2024, PacifiCorp entered into additional settlements associated with the 2020 Wildfires totaling $51 million with 167 plaintiffs.

The following table presents changes in PacifiCorp's liability for estimated losses associated with the Wildfires for the years ended December 31 (in millions):

	2023	2022	2021
Beginning balance	$ 424	$ 252	$ 252
Accrued losses	1,930	225	—
Payments[(1)]	(631)	(53)	—
Ending balance	$ 1,723	$ 424	$ 252

(1) Amounts represent payments made to settle certain claims associated with the 2020 Wildfires, including $549 million in December 2023 resulting from the above-described settlement agreements reached in December 2023 associated with the Archie Creek Complex Fire.

As of December 31, 2023 and 2022, $4 million and $24 million of PacifiCorp's liability for estimated losses associated with the Wildfires was included in Other current liabilities on the Consolidated Balance Sheets.

Until such time that settlement terms or other conclusions are reached to indicate that payments are expected to occur in the short-term, PacifiCorp's liability for estimated losses associated with the Wildfires is classified as a noncurrent liability captioned Wildfires liabilities on the Consolidated Balance Sheets.

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):

	2023	2022	2021
Beginning balance	$ 246	$ 116	$ 116
Accruals	253	161	—
Payments received	—	(31)	—
Ending balance	$ 499	$ 246	$ 116

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. As of December 31, 2022, the $246 million was included in Other assets on the Consolidated Balance Sheets. In January and February 2024, PacifiCorp received $338 million of insurance proceeds related to the 2020 Wildfires.

During the years ended December 31, 2023, 2022 and 2021, PacifiCorp recognized probable losses net of expected insurance recoveries associated with the Wildfires of $1,677 million, $64 million and $— million, respectively. No additional insurance recoveries beyond those accrued 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, the variation in the types of properties and damages and the ultimate outcome of legal actions.

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):

	2023	2022	2021
Customer Revenue:			
Retail:			
Residential	$ 2,156	$ 2,013	$ 1,914
Commercial	1,829	1,645	1,559
Industrial	1,179	1,163	1,125
Other retail	298	278	249
Total retail	5,462	5,099	4,847
Wholesale	165	260	157
Transmission	151	166	143
Other Customer Revenue	129	102	108
Total Customer Revenue	5,907	5,627	5,255
Other revenue	29	52	41
Total operating revenue	$ 5,936	$ 5,679	$ 5,296

(16) Preferred Stock

PacifiCorp has 3,500 thousand shares of Serial Preferred Stock authorized at the stated value of $100 per share. PacifiCorp had 24 thousand shares of Serial Preferred Stock issued and outstanding as of December 31, 2023 and 2022. 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.

PacifiCorp also has 16 million shares of No Par Serial Preferred Stock and 127 thousand shares of 5% Preferred Stock authorized, but no shares were issued or outstanding as of December 31, 2023 and 2022.

(17) Common Shareholder's Equity

Through PPW Holdings, 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, 2023, the most restrictive of these commitments prohibits PacifiCorp from making any distribution to PPW Holdings or BHE without prior state regulatory approval to the extent that it would reduce PacifiCorp's common equity below 44% of its total capitalization, excluding short-term debt and current maturities of long-term debt. As of December 31, 2023, PacifiCorp's actual common equity percentage, as calculated under this measure, was 50%.

These commitments also restrict PacifiCorp from making any distributions to either PPW Holdings 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, 2023, 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 $10 million and $9 million as of December 31, 2023 and 2022, 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 $48 million and $28 million as of December 31, 2023 and 2022, 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):

	2023	2022	2021
Supplemental disclosure of cash flow information:			
Interest paid, net of amounts capitalized	$ 432	$ 380	$ 395
Income taxes received, net	$ 292	$ 185	$ 120
Supplemental disclosure of non-cash investing and financing activities:			
Accruals related to property, plant and equipment additions	$ 862	$ 558	$ 254

(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 $168 million, $123 million and $70 million during the years ended December 31, 2023, 2022 and 2021, respectively. Amounts charged to PacifiCorp in 2023 and 2022 were primarily reflected in construction work in progress on the Consolidated Balance Sheets as of December 31, 2023 and 2022. Payables associated with the charges were $15 million and $16 million as of December 31, 2023 and 2022, respectively. Amounts charged by PacifiCorp to BHE and its subsidiaries under these agreements totaled $44 million, $23 million and $8 million during the years ended December 31, 2023, 2022 and 2021, respectively. Receivables associated with the charges were $8 million and $3 million as of December 31, 2023 and 2022, 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 $6 million, $8 million and $6 million during the years ended December 31, 2023, 2022 and 2021, 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 $24 million, $21 million and $19 million during the years ended December 31, 2023, 2022 and 2021, 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 $17 million, $8 million and $2 million during the years ended December 31, 2023, 2022 and 2021, respectively.

PacifiCorp is party to a tax-sharing agreement and is part of the Berkshire Hathaway consolidated U.S. federal income tax return. Federal and state income taxes receivable from BHE were $114 million and $84 million as of December 31, 2023 and 2022, respectively. For the years ended December 31, 2023, 2022 and 2021, cash refunded from BHE for federal and state income taxes totaled $292 million, $185 million and $120 million.

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, 2023, 2022 and 2021, coal purchases from PacifiCorp's equity investees totaled $139 million, $119 million and $148 million, respectively. Payables to PacifiCorp's equity investees were $34 million and $10 million as of December 31, 2023 and 2022, respectively.

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 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, 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. Depreciation and amortization decreased primarily from the impacts of certain regulatory mechanisms, partially offset by additional assets placed in-service. 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%. The unfavorable income tax benefit was mainly due to lower PTCs recognized from lower wind- and solar-powered generation, higher pretax income and the timing of state income tax benefits.

MidAmerican Energy's net income for 2022 was $961 million, an increase of $67 million, or 7%, compared to 2021 primarily due to higher electric utility margin, a favorable income tax benefit, higher natural gas utility margin and higher AFUDC, partially offset by higher depreciation and amortization expense, higher operations and maintenance expense, unfavorable changes in the cash surrender value of corporate-owned life insurance policies, higher non-service benefit plan costs and higher interest expense. Electric utility margin increased due to higher wholesale utility margin from higher margin per unit and higher wholesale customer volumes of 12.2% and higher retail utility margin, largely from higher retail customer volumes. Retail customer volumes increased 4.3% due to higher customer usage, reflecting the favorable impact of weather and an increase in certain industrial customer usage. Energy generated increased 6% primarily due to higher wind-powered generation, partially offset by lower coal-fueled generation, and energy purchased increased 19%. The favorable income tax benefit was mainly due to higher PTCs recognized from higher wind- and solar-powered generation, partially offset by the timing of state income tax benefits. Depreciation and amortization expense increased primarily from the impacts of certain regulatory mechanisms and additional assets placed in-service.

MidAmerican Funding -

MidAmerican Funding's net income for 2023 was $980 million, an increase of $33 million, or 3%, compared to 2022. MidAmerican Funding's net income for 2022 was $947 million, an increase of $64 million, or 7%, compared to 2021. 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.

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 profitability 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 managing 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):

	2023	2022	Change		2022	2021	Change	
Electric utility margin:								
Operating revenue	$ 2,673	$ 2,988	$ (315)	(11)%	$ 2,988	$ 2,529	$ 459	18 %
Cost of fuel and energy	501	679	(178)	(26)	679	539	140	26
Electric utility margin	2,172	2,309	(137)	(6)%	2,309	1,990	319	16 %
Natural gas utility margin:								
Operating revenue	713	1,030	(317)	(31)%	1,030	1,003	27	3 %
Natural gas purchased for resale	451	762	(311)	(41)	762	760	2	— %
Natural gas utility margin	262	268	(6)	(2)%	268	243	25	10 %
Utility margin	$ 2,434	$ 2,577	$ (143)	(6)%	$ 2,577	$ 2,233	$ 344	15 %
Other operating revenue	7	7	—	— %	7	15	(8)	(53)%
Other cost of sales	—	1	(1)	(100)	1	1	—	—
Operations and maintenance	851	828	23	3	828	775	53	7
Depreciation and amortization	908	1,168	(260)	(22)	1,168	914	254	28
Property and other taxes	161	149	12	8	149	142	7	5
Operating income	$ 521	$ 438	$ 83	19 %	$ 438	$ 416	$ 22	5 %

* Not meaningful.

Electric Utility Margin

A comparison of key operating results related to electric utility margin is as follows for the years ended December 31:

	2023	2022	Change		2022	2021	Change	
Utility margin (in millions):								
Operating revenue	$ 2,673	$ 2,988	$ (315)	(11)%	$ 2,988	$ 2,529	$ 459	18 %
Cost of fuel and energy	501	679	(178)	(26)	679	539	140	26
Utility margin	$ 2,172	$ 2,309	$ (137)	(6)%	$ 2,309	$ 1,990	$ 319	16 %
Sales (GWhs):								
Residential	6,759	7,006	(247)	(4)%	7,006	6,718	288	4 %
Commercial	3,992	4,017	(25)	(1)	4,017	3,841	176	5
Industrial	17,307	16,646	661	4	16,646	15,944	702	4
Other	1,617	1,621	(4)	—	1,621	1,571	50	3
Total retail	29,675	29,290	385	1	29,290	28,074	1,216	4
Wholesale	15,129	17,964	(2,835)	(16)	17,964	16,011	1,953	12
Total sales	44,804	47,254	(2,450)	(5)%	47,254	44,085	3,169	7 %
Average number of retail customers (in thousands)	820	813	7	1 %	813	804	9	1 %
Average revenue per MWh:								
Retail	$ 77.82	$ 79.23	$ (1.41)	(2)%	$ 79.23	$ 75.84	$ 3.39	4 %
Wholesale	$ 17.92	$ 31.07	$ (13.15)	(42)%	$ 31.07	$ 18.92	$ 12.15	64 %
Heating degree days	5,371	6,449	(1,078)	(17)%	6,449	5,704	745	13 %
Cooling degree days	1,255	1,274	(19)	(1)%	1,274	1,331	(57)	(4)%
Sources of energy (GWhs)[1]:								
Wind and other[2]	24,877	28,129	(3,252)	(12)%	28,129	23,374	4,755	20 %
Coal	9,961	10,078	(117)	(1)	10,078	12,313	(2,235)	(18)
Nuclear	3,790	3,782	8	—	3,782	3,934	(152)	(4)
Natural gas	2,184	1,504	680	45	1,504	1,398	106	8
Total energy generated	40,812	43,493	(2,681)	(6)	43,493	41,019	2,474	6
Energy purchased	4,772	4,594	178	4	4,594	3,865	729	19
Total	45,584	48,087	(2,503)	(5)%	48,087	44,884	3,203	7 %
Average cost of energy per MWh:								
Energy generated[3]	$ 6.80	$ 7.42	$ (0.62)	(8)%	$ 7.42	$ 7.12	$ 0.30	4 %
Energy purchased	$ 46.86	$ 77.59	$ (30.73)	(40)%	$ 77.59	$ 64.04	$ 13.55	21%

* Not meaningful.

(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:

	2023	2022	Change		2022	2021	Change	
Utility margin (in millions):								
Operating revenue	$ 713	$ 1,030	$ (317)	(31)%	$ 1,030	$ 1,003	$ 27	3 %
Natural gas purchased for resale	451	762	(311)	(41)	762	760	2	—
Utility margin	$ 262	$ 268	$ (6)	(2)%	$ 268	$ 243	$ 25	10 %
Throughput (000's Dths):								
Residential	47,558	56,100	(8,542)	(15)%	56,100	48,984	7,116	15 %
Commercial	22,715	26,298	(3,583)	(14)	26,298	23,240	3,058	13
Industrial	5,799	6,039	(240)	(4)	6,039	5,287	752	14
Other	76	75	1	1	75	68	7	10
Total retail sales	76,148	88,512	(12,364)	(14)	88,512	77,579	10,933	14
Wholesale sales	30,764	30,996	(232)	(1)	30,996	34,337	(3,341)	(10)
Total sales	106,912	119,508	(12,596)	(11)	119,508	111,916	7,592	7
Natural gas transportation service	106,422	102,827	3,595	3	102,827	112,631	(9,804)	(9)
Total throughput	213,334	222,335	(9,001)	(4)%	222,335	224,547	(2,212)	(1)%
Average number of retail customers (in thousands)	796	789	7	1 %	789	781	8	1 %
Average revenue per retail Dth sold	$ 7.80	$ 9.19	$ (1.39)	(15)%	$ 9.19	$ 10.59	$ (1.40)	(13)%
Heating degree days	5,668	6,810	(1,142)	(17)%	6,810	6,000	810	14 %
Average cost of natural gas per retail Dth sold	$ 4.98	$ 6.66	$ (1.68)	(25)%	$ 6.66	$ 7.95	$ (1.29)	(16)%
Combined retail and wholesale average cost of natural gas per Dth sold	$ 4.22	$ 6.38	$ (2.16)	(34)%	$ 6.38	$ 6.79	$ (0.41)	(6)%

* Not meaningful.

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:

- a $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
- a $7 million decrease in Multi-Value Projects ("MVP") transmission revenue; partially offset by
- a $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:

- an $8 million decrease in customer usage, including $19 million from the unfavorable impact of weather; and
- a $2 million decrease from lower refunds related to amortization of excess accumulated deferred income taxes arising from 2017 tax reform (offset in income tax benefit); partially offset by
- a $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.

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. PTC's totaled $681 million, $710 million and $574 million in 2023, 2022 and 2021, respectively.

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.

Year Ended December 31, 2022 Compared to Year Ended December 31, 2021

MidAmerican Energy -

Electric utility margin increased $319 million, or 16%, for 2022 compared to 2021 primarily due to:

- a $250 million increase in wholesale utility margin due to higher margin per unit of $237 million, reflecting higher market prices and lower energy costs, and higher volumes of 12.2%;
- a $66 million increase in retail utility margin primarily due to $62 million from higher customer usage, including $7 million from the favorable impact of weather; and $9 million, net of energy costs, from higher recoveries through bill riders (offset in operations and maintenance expense and income tax benefit); partially offset by $6 million in 2021 from liquidated damages related to a wind-powered generation project. Retail customer volumes increased 4.3%; and
- a $3 million increase in Multi-Value Projects ("MVP") transmission revenue.

Natural gas utility margin increased $25 million, or 10%, for 2022 compared to 2021 primarily due to:

- an $18 million increase in customer usage, including $9 million from the favorable impact of weather;
- a $5 million increase from higher refunds related to amortization of excess accumulated deferred income taxes arising from 2017 tax reform (offset in income tax benefit); and
- a $3 million increase in natural gas transportation margin, reflecting higher prices.

Operations and maintenance increased $53 million, or 7%, for 2022 compared to 2021 primarily due to higher other power generation costs of $21 million from additional wind turbines and easements, higher electric distribution costs of $17 million reflecting greater tree-trimming efforts, higher steam generation costs of $13 million and higher transmission costs from MISO of $6 million, partially offset by lower gas distribution costs of $6 million.

Depreciation and amortization increased $254 million, or 28%, for 2022 compared to 2021 primarily due to $181 million from higher Iowa revenue sharing accruals, $40 million related to new and repowered wind-powered generating facilities and other plant placed in-service and $31 million from a regulatory mechanism that provides customers the retail energy benefits of certain wind-powered generation projects.

Property and other taxes increased $7 million, or 5%, for 2022 compared to 2021 primarily due to higher wind turbine property taxes.

Interest expense increased $11 million, or 4%, for 2022 compared to 2021 primarily due to a higher average long-term debt balance and higher variable interest rates.

Allowance for borrowed and equity funds increased $14 million, or 27%, for 2022 compared to 2021 primarily due to higher construction work-in-progress balances related to wind- and solar-powered generation projects.

Other, net decreased $53 million, or 100%, for 2022 compared to 2021 primarily due to lower cash surrender values of corporate-owned life insurance policies of $37 million, higher non-service costs of postretirement employee benefit plans of $17 million and lower other investment values, partially offset by higher interest income.

Income tax benefit increased $95 million, or 14%, for 2022 compared to 2021, and the effective tax rate was (403)% for 2022 and (308)% for 2021. The change in the effective tax rate was substantially due to an increase of $136 million in PTCs, partially offset by state income tax impacts.

MidAmerican Funding -

Income tax benefit for MidAmerican Funding increased $96 million, or 14%, for 2022 compared to 2021, and the effective tax rate was (454)% for 2022 and (335)% for 2021. The change in effective tax rates was due principally to the factors discussed for MidAmerican Energy.

Liquidity and Capital Resources

As of December 31, 2023, MidAmerican Energy's and MidAmerican Funding's total net liquidity were as follows (in millions):

MidAmerican Energy:		
Cash and cash equivalents	$	636
Credit facilities, maturing 2024 and 2026		1,505
Less:		
Tax-exempt bond support		(306)
Net credit facilities		1,199
MidAmerican Energy total net liquidity	$	1,835
MidAmerican Funding:		
MidAmerican Energy total net liquidity	$	1,835
Cash and cash equivalents		1
MHC, Inc. credit facility, maturing 2024		4
MidAmerican Funding total net liquidity	$	1,840

Operating Activities

MidAmerican Energy's net cash flows from operating activities were $2,217 million, $2,174 million and $1,617 million for 2023, 2022 and 2021, respectively. MidAmerican Funding's net cash flows from operating activities were $2,203 million, $2,161 million and $1,605 million for 2023, 2022 and 2021, respectively. 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. Cash flows from operating activities increased for 2022 compared to 2021 primarily due to higher utility margins for MidAmerican Energy's regulated electric and natural gas businesses, higher income tax receipts and lower payments to vendors. Higher utility margins are partially attributable to timing of the recovery of higher natural gas costs caused by the February 2021 polar vortex weather event.

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 $(1,837) million, $(1,867) million and $(1,911) million for 2023, 2022 and 2021, respectively. MidAmerican Funding's net cash flows from investing activities were $(1,825) million, $(1,868) million and $(1,912) million for 2023, 2022 and 2021, 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 $(6) million, $(278) million and $488 million for 2023, 2022 and 2021, respectively. MidAmerican Funding's net cash flows from financing activities were $(6) million, $(262) million and $501 million for 2023, 2022 and 2021, respectively. Proceeds from long-term debt reflect MidAmerican Energy's issuance 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 July 2021, MidAmerican Energy issued $500 million of its 2.70% First Mortgage Bonds due August 2052. In 2023 and 2022, MidAmerican Energy paid $1,025 million and $275 million in cash dividends to its parent company, MHC Inc. In 2023 and 2022, MidAmerican Funding paid $1,025 million and $69 million, respectively, in cash distributions to its sole member, BHE. MidAmerican Funding paid $189 million in 2022 and received $12 million in 2021, respectively, through its note payable with BHE.

In January 2024, MidAmerican Energy issued $600 million of its 5.30% First Mortgage Bonds due February 2055. MidAmerican Energy intends, within 24 months of the issuance date, to allocate an amount equal to the net proceeds to finance, in whole or in part, new or existing investments or expenditures made in one or more eligible projects in alignment with BHE's Green Financing Framework.

Debt Authorizations and Related Matters

Short-term Debt

MidAmerican Energy has authority from the FERC to issue, through April 2, 2024, commercial paper and bank notes aggregating $1.5 billion. MidAmerican Energy has a $1.5 billion unsecured credit facility expiring in June 2026. 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, 2023, MidAmerican Energy estimated it would be able to issue up to $8.3 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; 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		
	2021	2022	2023	2024	2025	2026
Wind generation	$ 964	$ 685	$ 744	$ 815	$ 1,636	$ 1,661
Electric distribution	257	311	369	314	304	308
Electric transmission	199	145	205	235	306	338
Solar generation	132	119	13	14	82	30
Other	360	609	502	502	433	455
Total	$ 1,912	$ 1,869	$ 1,833	$ 1,880	$ 2,761	$ 2,792

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 $608 million for 2023, $72 million for 2022 and $540 million for 2021. MidAmerican Energy placed in-service 200 MWs during 2023 and 294 MWs during 2021. Planned spending for the construction of additional wind-powered generating facilities totals $515 million, $1,196 million and $998 million for 2024, 2025 and 2026, respectively.
  - Repowering of wind-powered generating facilities totaled $47 million for 2023, $500 million for 2022 and $354 million for 2021. Planned spending for repowering totals $228 million, $382 million and $601 million in 2024, 2025 and 2026, respectively. MidAmerican Energy expects its repowered facilities to meet IRS guidelines for the re-establishment of PTCs 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, primarily consisting of 141 MWs of small- and utility-scale solar generation, all of which were placed in-service in 2022, with total spend of $13 million in 2023, $119 million in 2022 and $132 million in 2021. Planned spending for the construction and operation of additional solar-powered generating facilities totals $14 million, $82 million and $30 million for 2024, 2025 and 2026, 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 $7.3 billion on long-term debt, including $385 million due in 2024. Additionally, MidAmerican Funding has cash requirements relating to interest payments on its long-term debt of $91 million, including $17 million due in 2024.

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.

Quad Cities Generating Station Operating Status

Constellation Energy Generation, LLC ("Constellation Energy"), the operator of Quad Cities Generating Station Units 1 and 2 ("Quad Cities Station") of which MidAmerican Energy has a 25% ownership interest, receives financial support for continued operation of Quad Cities Station from the zero emission standard enacted by the Illinois legislature in December 2016. 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. The proceeds from the ZECs provide Constellation Energy additional revenue through 2027 as an incentive for continued operation of Quad Cities Station. MidAmerican Energy does not receive additional revenue from the subsidy.

The PJM Interconnection, L.L.C. ("PJM") capacity market includes a Minimum Offer Price Rule ("MOPR"). If a generation resource is subjected to a MOPR, its offer price in the market is adjusted to effectively remove the revenues it receives through a state government-provided financial support program like the Illinois zero emission standard, resulting in a higher offer that may not clear the capacity market. Prior to December 19, 2019, the PJM MOPR applied only to certain new gas-fueled resources.

On December 19, 2019, the FERC issued an order requiring the PJM to broadly apply the MOPR to all new and existing resources, including nuclear. This greatly expanded the breadth and scope of the PJM's MOPR, which became effective as of the PJM's capacity auction for the 2022-2023 planning year. While the FERC included some limited exemptions, no exemptions were available to state-supported nuclear resources, such as Quad Cities Station. The FERC denied rehearing of that order on April 16, 2020. A number of parties, including Constellation Energy, have filed petitions for review of the FERC's orders in this proceeding, which remain pending before the Court of Appeals for the Seventh Circuit. MidAmerican Energy cannot predict the outcome of this proceeding.

While this litigation is pending, the MOPR applied to Quad Cities Station in the capacity auction for the 2022-2023 planning year in May 2021, which prevented Quad Cities Station from clearing in that capacity auction.

At the direction of the PJM Board of Managers, the PJM and its stakeholders developed further MOPR reforms to ensure that the capacity market rules respect and accommodate state resource preferences such as the ZEC programs. The PJM filed related tariff revisions with the FERC on July 30, 2021, and, on September 29, 2021, the PJM's proposed MOPR reforms became effective by operation of law. Under the new tariff provisions, the MOPR applied in the capacity auction for the 2023-2024 delivery year but did not restrict the offers of Quad Cities Station, which cleared in the capacity auction. Requests for rehearing of the FERC's notice establishing the effective date for the PJM's proposed market reforms were filed in October 2021 and denied by operation of law on November 4, 2021. Several parties have filed petitions for review of the FERC's orders in this proceeding, which remain pending before the Court of Appeals for the Third Circuit.

Assuming the continued effectiveness of the Illinois zero emission standard, Constellation Energy no longer considers Quad Cities Station to be at heightened risk for early retirement. However, to the extent the Illinois zero emission standard does not operate as expected over its full term, Quad Cities Station would be at heightened risk for early retirement. The FERC provided no new mechanism for accommodating state-supported resources like Quad Cities Station other than the existing Fixed Resource Requirement ("FRR") mechanism under which an entire utility zone would be removed from PJM's capacity auction along with sufficient resources to support the load in such zone. Depending on the outcome of the proceedings related to the PJM MOPR, the continued effectiveness of the Illinois zero emission standard may be undermined unless the PJM adopts further changes to the MOPR or Illinois implements an FRR mechanism, under which Quad Cities Station would be removed from the PJM's capacity auction.

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, 2023, 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, 2023, MidAmerican Energy would have been required to post $85 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 $600 million and total regulatory liabilities were $1,079 million as of December 31, 2023. 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, 2023, 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, 2023. Additionally, no indicators of impairment were identified as of December 31, 2023. 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, 2023, MidAmerican Energy recognized a net liability totaling $45 million for the funded status of its defined benefit pension and other postretirement benefit plans. As of December 31, 2023, amounts not yet recognized as a component of net periodic benefit cost that were included in regulatory assets and regulatory liabilities totaled $16 million and $16 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, 2023.

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 2028 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, 2023 Benefit Obligations:				
Discount rate	$ (23)	$ 25	$ (9)	$ 9
Effect on 2023 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 2017 federal tax rate change from 35% to 21%, certain property-related basis differences, and other various differences. As of December 31, 2023, these amounts were recognized as a net regulatory liability of $102 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, 2023 and 2022, MidAmerican Energy had short- and long-term variable-rate obligations totaling $306 million 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, 2023, 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, 2023 and 2022.

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, 2023, MidAmerican Energy's aggregate direct credit exposure from electric wholesale marketing counterparties was not material.

Item 8. Financial Statements and Supplementary Data

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, 2023 and 2022, 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, 2023, 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, 2023 and 2022, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2023, 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 audit 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 future 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 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 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 23, 2024

We have served as MidAmerican Energy's auditor since 1999.

MIDAMERICAN ENERGY COMPANY
BALANCE SHEETS
(Amounts in millions)

	As of December 31,	
	2023	**2022**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 636	$ 258
Trade receivables, net	272	536
Income tax receivable	1	42
Inventories	364	277
Prepayments	113	91
Other current assets	39	66
Total current assets	1,425	1,270
Property, plant and equipment, net	21,970	21,091
Regulatory assets	600	550
Investments and restricted investments	1,030	902
Other assets	210	165
Total assets	$ 25,235	$ 23,978

The accompanying notes are an integral part of these financial statements.

MIDAMERICAN ENERGY COMPANY
BALANCE SHEETS (continued)
(Amounts in millions)

	As of December 31,	
	2023	2022
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities:		
Accounts payable	$ 543	$ 536
Accrued interest	106	85
Accrued property, income and other taxes	197	170
Current portion of long-term debt	539	317
Other current liabilities	102	93
Total current liabilities	1,487	1,201
Long-term debt	8,227	7,412
Regulatory liabilities	1,079	1,119
Deferred income taxes	3,494	3,433
Asset retirement obligations	768	683
Other long-term liabilities	577	485
Total liabilities	15,632	14,333
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	9,042	9,084
Total shareholder's equity	9,603	9,645
Total liabilities and shareholder's equity	$ 25,235	$ 23,978

The accompanying notes are an integral part of these financial statements.

MIDAMERICAN ENERGY COMPANY
STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2023	2022	2021
Operating revenue:			
Regulated electric	$ 2,673	$ 2,988	$ 2,529
Regulated natural gas and other	720	1,037	1,018
Total operating revenue	3,393	4,025	3,547
Operating expenses:			
Cost of fuel and energy	501	679	539
Cost of natural gas purchased for resale and other	451	763	761
Operations and maintenance	851	828	775
Depreciation and amortization	908	1,168	914
Property and other taxes	161	149	142
Total operating expenses	2,872	3,587	3,131
Operating income	521	438	416
Other income (expense):			
Interest expense	(346)	(313)	(302)
Allowance for borrowed funds	19	15	13
Allowance for equity funds	59	51	39
Other, net	36	—	53
Total other income (expense)	(232)	(247)	(197)
Income before income tax expense (benefit)	289	191	219
Income tax expense (benefit)	(693)	(770)	(675)
Net income	$ 982	$ 961	$ 894

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, 2020	$ —	$ 561	$ 7,504	$ 8,065
Net income	—	—	894	894
Other equity transactions	—	—	1	1
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

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, 2023	2022	2021
Cash flows from operating activities:			
Net income	$ 982	$ 961	$ 894
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	908	1,168	914
Amortization of utility plant to other operating expenses	34	35	34
Allowance for equity funds	(59)	(51)	(39)
Deferred income taxes and amortization of investment tax credits	90	33	153
Settlements of asset retirement obligations	(21)	(85)	(103)
Other, net	46	51	21
Changes in other operating assets and liabilities:			
Trade receivables and other assets	254	(11)	(293)
Inventories	(87)	(43)	44
Pension and other postretirement benefit plans, net	3	8	(4)
Accrued property, income and other taxes, net	76	40	(71)
Accounts payable and other liabilities	(9)	68	67
Net cash flows from operating activities	2,217	2,174	1,617
Cash flows from investing activities:			
Capital expenditures	(1,833)	(1,869)	(1,912)
Purchases of marketable securities	(243)	(499)	(213)
Proceeds from sales of marketable securities	227	492	207
Other, net	12	9	7
Net cash flows from investing activities	(1,837)	(1,867)	(1,911)
Cash flows from financing activities:			
Common stock dividends	(1,025)	(275)	—
Proceeds from long-term debt	1,338	—	492
Repayments of long-term debt	(317)	(2)	(1)
Other, net	(2)	(1)	(3)
Net cash flows from financing activities	(6)	(278)	488
Net change in cash and cash equivalents and restricted cash and cash equivalents	374	29	194
Cash and cash equivalents and restricted cash and cash equivalents at beginning of year	268	239	45
Cash and cash equivalents and restricted cash and cash equivalents at end of year	$ 642	$ 268	$ 239

The accompanying notes are an integral part of these 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 owns subsidiaries principally engaged in energy businesses. BHE is a consolidated 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, 2023, 2022 and 2021.

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 Board ("IUB"), 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, 2023 and 2022 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,	
	2023	2022
Cash and cash equivalents	$ 636	$ 258
Restricted cash and cash equivalents in other current assets	6	10
Total cash and cash equivalents and restricted cash and cash equivalents	$ 642	$ 268

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 change 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):

	2023	2022	2021
Beginning balance	$ 14	$ 12	$ 12
Charged to operating costs and expenses, net	8	11	10
Write-offs, net	(10)	(9)	(10)
Ending balance	$ 12	$ 14	$ 12

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 $240 million and $175 million as of December 31, 2023 and 2022, respectively, coal stocks, totaling $89 million and $68 million as of December 31, 2023 and 2022, respectively, and natural gas in storage, totaling $29 million and $27 million as of December 31, 2023 and 2022, 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 $4 million and $22 million higher as of December 31, 2023 and 2022, 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, 2023 and 2022, unbilled revenue was $97 million and $102 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 under collection included in trade receivables, net at December 31, 2023 and 2022, was $29 million and $156 million, respectively.

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 on the Consolidated Statements of Operations.

New Accounting Pronouncements

In November 2023, the FASB issued 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 is currently evaluating the impact of adopting this guidance on its Financial Statements and disclosures included within Notes to 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. MidAmerican Energy is currently evaluating the impact of adopting this guidance on its 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	2023	2022
Utility plant:			
Generation	20-62 years	$ 18,129	$ 18,582
Transmission	55-80 years	2,834	2,662
Electric distribution	15-80 years	5,288	4,931
Natural gas distribution	30-75 years	2,294	2,144
Utility plant in-service		28,545	28,319
Accumulated depreciation and amortization		(7,841)	(8,024)
Utility plant in-service, net		20,704	20,295
Nonregulated property, net of accumulated depreciation and amortization	20-50 years	6	6
		20,710	20,301
Construction work-in-progress		1,260	790
Property, plant and equipment, net		$ 21,970	$ 21,091

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:

	2023	2022	2021
Electric	3.3 %	3.2 %	3.3 %
Natural gas	2.8 %	2.9 %	2.8 %

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, 2023, 2022 and 2021, $29 million, $296 million, and $115 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, 2023 (dollars in millions):

	Company Share	Plant in Service	Accumulated Depreciation and Amortization	Construction Work-in-Progress
Louisa Unit No. 1	88 %	$ 983	$ 531	$ 5
Quad Cities Unit Nos. 1 & 2[(1)]	25	737	496	11
Walter Scott, Jr. Unit No. 3	79	1,017	888	14
Walter Scott, Jr. Unit No. 4[(2)]	60	170	123	8
George Neal Unit No. 4	41	330	191	6
Ottumwa Unit No. 1[(2)]	52	433	299	8
George Neal Unit No. 3	72	557	375	20
Transmission facilities	Various	274	100	3
Total		$ 4,501	$ 3,003	$ 75

(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 $891 million and $183 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	2023	2022
Asset retirement obligations[(1)]	12 years	$ 541	$ 469
Employee benefit plans[(2)]	9 years	16	47
Unrealized loss on regulated derivative contracts	1 year	11	—
Other	Various	32	34
Total		$ 600	$ 550

(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 $598 million and $548 million as of December 31, 2023 and 2022, 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	2023	2022
Cost of removal[1]	28 years	$ 411	$ 392
Asset retirement obligations[2]	30 years	360	247
Iowa electric revenue sharing[3]	Various	127	312
Deferred income taxes[4]	Various	102	72
Pre-funded AFUDC on transmission MVPs[5]	56 years	32	34
Employee benefit plans[6]	N/A	16	—
Unrealized gain on regulated derivative contracts	1 year	—	31
Other	Various	31	31
Total		$ 1,079	$ 1,119

(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) 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.

(5) 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) 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.

(6) Investments and Restricted Investments

Investments and restricted investments consists of the following amounts as of December 31 (in millions):

	2023	2022
Nuclear decommissioning trust	$ 767	$ 664
Rabbi trusts	239	215
Other	24	23
Total	$ 1,030	$ 902

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, 2023 and 2022, the fair value of the trust's funds was invested as follows: 56% and 54%, respectively, in domestic common equity securities, 33% and 32%, respectively, in U.S. government securities, 9% and 11%, respectively, in domestic corporate debt securities and 2% and 3%, 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):

	2023	2022
Credit facilities	$ 1,505	$ 1,505
Less:		
Variable-rate tax-exempt bond support	(306)	(370)
Net credit facilities	$ 1,199	$ 1,135

As of December 31, 2023, MidAmerican Energy has a $1.5 billion unsecured credit facility expiring in June 2026 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 2024 and has a variable interest rate based on SOFR, plus a spread.

MidAmerican Energy had no commercial paper borrowings outstanding of as of December 31, 2023 and 2022. 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, 2023, 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, 2024.

As of December 31, 2023 and 2022, MidAmerican Energy had $345 million and $371 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, 2023 and 2022, MidAmerican Energy had $55 million and $34 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	2023	2022
First mortgage bonds:			
3.70%, due 2023	$ —	$ —	$ 250
3.50%, due 2024	500	500	500
3.10%, due 2027	375	374	374
3.65%, due 2029	850	858	859
4.80%, due 2043	350	347	347
4.40%, due 2044	400	396	395
4.25%, due 2046	450	446	446
3.95%, due 2047	475	471	471
3.65%, due 2048	700	690	689
4.25%, due 2049	900	876	875
3.15%, due 2050	600	592	592
2.70%, due 2052	500	492	492
5.35%, due 2034	350	347	—
5.85%, due 2054	1,000	989	—
Notes:			
6.75% Series, due 2031	400	398	397
5.75% Series, due 2035	300	299	298
5.80% Series, due 2036	350	348	348
Transmission upgrade obligations, 3.24% to 7.84%, due 2036 to 2043	70	39	27
Variable-rate tax-exempt bond obligation series: (weighted average interest rate-2023-4.81%, 2022-3.83%):			
Due 2023, issued in 1993	—	—	7
Due 2023, issued in 2008	—	—	57
Due 2024	35	35	35
Due 2025	13	13	13
Due 2036	33	33	33
Due 2038	45	45	45
Due 2046	30	29	30
Due 2047	150	149	149
Total long-term debt	$ 8,876	$ 8,766	$ 7,729

Reflected as:

	2023	2022
Current portion of long-term debt	$ 539	$ 317
Long-term debt	8,227	7,412
Total long-term debt	$ 8,766	$ 7,729

The annual repayments of MidAmerican Energy's long-term debt for the years beginning January 1, 2024, and thereafter, excluding unamortized premiums, discounts and debt issuance costs, are as follows (in millions):

2024	$	539
2025		17
2026		4
2027		379
2028		4
2029 and thereafter		7,933

In January 2024, MidAmerican Energy issued $600 million of its 5.30% First Mortgage Bonds due February 2055. MidAmerican Energy intends, within 24 months of the issuance date, to allocate an amount equal to the net proceeds to finance, in whole or in part, new or existing investments or expenditures made in one or more eligible projects in alignment with BHE's Green Financing Framework.

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 $24 billion of MidAmerican Energy's eligible property, based on original cost, was subject to the lien of the mortgage as of December 31, 2023. 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, 2023 and 2022. 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, 2023, MidAmerican Energy was in compliance with all of its applicable long-term debt covenants.

In March 1999, MidAmerican Energy committed to the IUB 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 IUB 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 IUB 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, 2023, MidAmerican Energy's common equity ratio was 55% 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 $3.6 billion as of December 31, 2023, 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):

	2023	2022	2021
Current:			
Federal	$ (755)	$ (769)	$ (736)
State	(28)	(34)	(92)
	(783)	(803)	(828)
Deferred:			
Federal	109	77	189
State	(18)	(43)	(35)
	91	34	154
Investment tax credits	(1)	(1)	(1)
Total	$ (693)	$ (770)	$ (675)

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:

	2023	2022	2021
Federal statutory income tax rate	21 %	21 %	21 %
Income tax credits	(236)	(372)	(262)
State income tax, net of federal income tax impacts	(12)	(32)	(46)
Effects of ratemaking	(12)	(23)	(20)
Other, net	(1)	3	(1)
Effective income tax rate	(240)%	(403)%	(308)%

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, 2023, 2022 and 2021 totaled $681 million, $710 million and $574 million, respectively.

MidAmerican Energy's net deferred income tax liability consists of the following as of December 31 (in millions):

	2023	2022
Deferred income tax assets:		
Regulatory liabilities	$ 218	$ 194
Asset retirement obligations	204	191
State carryforwards	68	61
Revenue sharing	34	87
Employee benefits	25	37
Other	68	24
Total deferred income tax assets	617	594
Valuation allowances	(2)	(2)
Total deferred income tax assets, net	615	592
Deferred income tax liabilities:		
Property-related items	(3,972)	(3,895)
Regulatory assets	(134)	(128)
Other	(3)	(2)
Total deferred income tax liabilities	(4,109)	(4,025)
Net deferred income tax liability	$ (3,494)	$ (3,433)

As of December 31, 2023, MidAmerican Energy's state tax carryforwards, principally related to $1 billion of net operating losses, expire at various intervals between 2024 and 2042.

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, 2019, 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):

	2023	2022
Beginning balance	$ 16	$ 13
Additions based on tax positions related to the current year	10	15
Interest	1	—
Reductions based on tax positions related to the current year	(5)	(12)
Ending balance	$ 22	$ 16

As of December 31, 2023, MidAmerican Energy had unrecognized tax benefits totaling $48 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. For the years ended December 31, 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. In 2022, the defined benefit pension plan recorded a curtailment gain of $10 million as a result of certain plan amendments.

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 2023, 2022 and 2021, MidAmerican Energy's share of the pension net periodic benefit credit was $(5) million, $(2) million and $(20) million, respectively. MidAmerican Energy's share of the other postretirement net periodic benefit cost (credit) in 2023, 2022 and 2021 totaled $2 million, $(2) million and $1 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		
	2023	2022	2021	2023	2022	2021
Service cost	$ 10	$ 15	$ 20	$ 5	$ 8	$ 9
Interest cost	32	23	22	13	8	8
Expected return on plan assets	(30)	(27)	(37)	(14)	(14)	(10)
Curtailment	—	(10)	—	—	—	—
Settlement	(3)	4	(5)	—	—	—
Net amortization	—	1	1	—	(2)	(4)
Net periodic benefit cost	$ 9	$ 6	$ 1	$ 4	$ —	$ 3

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	
	2023	2022	2023	2022
Plan assets at fair value, beginning of year	$ 490	$ 704	$ 240	$ 308
Employer contributions	7	7	3	3
Participant contributions	—	—	1	1
Actual return on plan assets	64	(130)	51	(58)
Settlement	—	(57)	—	—
Benefits paid	(45)	(34)	(17)	(14)
Plan assets at fair value, end of year	$ 516	$ 490	$ 278	$ 240

The following table is a reconciliation of the benefit obligations for the years ended December 31 (in millions):

	Pension		Other Postretirement	
	2023	2022	2023	2022
Benefit obligation, beginning of year	$ 586	$ 781	$ 243	$ 285
Service cost	10	15	5	8
Interest cost	32	23	13	8
Participant contributions	—	—	1	1
Actuarial loss (gain)	15	(129)	(4)	(64)
Amendment	—	(3)	—	19
Curtailment	—	(10)	—	—
Settlement	—	(57)	—	—
Benefits paid	(45)	(34)	(17)	(14)
Benefit obligation, end of year	$ 598	$ 586	$ 241	$ 243
Accumulated benefit obligation, end of year	$ 564	$ 551		

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	
	2023	2022	2023	2022
Plan assets at fair value, end of year	$ 516	$ 490	$ 278	$ 240
Less - Benefit obligation, end of year	598	586	241	243
Funded status	$ (82)	$ (96)	$ 37	$ (3)
Amounts recognized on the Balance Sheets:				
Other assets	$ 3	$ —	$ 37	$ —
Other current liabilities	(8)	(8)	—	—
Other long-term liabilities	(77)	(88)	—	(3)
Amounts recognized	$ (82)	$ (96)	$ 37	$ (3)

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 $149 million and $134 million as of December 31, 2023 and 2022, 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. For each of the years ended December 31, 2023 and 2022, the accumulated benefit obligation and projected benefit obligation for the SERP was $85 million and $85 million, 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	
	2023	2022	2023	2022
Net loss (gain)	$ (19)	$ (4)	$ (30)	$ 11
Prior service cost (credit)	(3)	(3)	18	19
Total	$ (22)	$ (7)	$ (12)	$ 30

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, 2023 and 2022 is as follows (in millions):

	Regulatory Asset	Regulatory Liability	Receivables (Payables) with Affiliates	Total
Pension				
Balance, December 31, 2021	$ 22	$ (55)	$ 8	$ (25)
Net loss (gain) arising during the year	(7)	58	(25)	26
Net prior service cost (credit) arising during the year	—	—	(3)	(3)
Settlement	—	(4)	—	(4)
Net amortization	(1)	—	—	(1)
Total	(8)	54	(28)	18
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)

	Regulatory Asset	Regulatory Liability	Receivables (Payables) with Affiliates	Total
Other Postretirement				
Balance, December 31, 2021	$ 20	$ —	$ (21)	$ (1)
Net loss (gain) arising during the year	10	—	(1)	9
Net prior service cost (credit) arising during the year	—	—	19	19
Net amortization	3	—	—	3
Total	13	—	18	31
Balance, December 31, 2022	33	—	(3)	30
Net loss (gain) 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)

Plan Assumptions

Assumptions used to determine benefit obligations and net periodic benefit cost were as follows:

	Pension			Other Postretirement		
	2023	**2022**	**2021**	**2023**	**2022**	**2021**
Benefit obligations as of December 31:						
Discount rate	5.45 %	5.70 %	3.05 %	5.45 %	5.60 %	2.95 %
Rate of compensation increase	3.00 %	3.00 %	2.75 %	N/A	N/A	N/A
Interest crediting rates for cash balance plan						
2021	N/A	N/A	1.19 %	N/A	N/A	N/A
2022	N/A	3.74 %	1.19 %	N/A	N/A	N/A
2023	3.50 %	3.74 %	1.19 %	N/A	N/A	N/A
2024	3.50 %	3.74 %	1.19 %	N/A	N/A	N/A
2025	3.50 %	3.74 %	1.19 %	N/A	N/A	N/A
2026 and beyond	3.50 %	3.74 %	1.19 %	N/A	N/A	N/A
Net periodic benefit cost for the years ended December 31:						
Discount rate	5.70 %	3.05 %	2.75 %	5.60 %	2.95 %	2.65 %
Expected return on plan assets(1)	6.35 %	4.30 %	5.60 %	6.80 %	5.30 %	4.00 %
Rate of compensation increase	3.00 %	2.75 %	2.75 %	N/A	N/A	N/A
Interest crediting rates for cash balance plan	3.50 %	3.74 %	1.19 %	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 5.52% for 2023, 4.21% for 2022 and 2.39% for 2021.

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.

	2023	**2022**
Assumed healthcare cost trend rates as of December 31:		
Healthcare cost trend rate assumed for next year	6.20 %	6.50 %
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	2028	2028

Contributions and Benefit Payments

Employer contributions to the pension and other postretirement benefit plans are expected to be $8 million and $2 million, respectively, during 2024. 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 2024 through 2028 and for the five years thereafter are summarized below (in millions):

	Projected Benefit Payments	
	Pension	**Other Postretirement**
2024	$ 54	$ 22
2025	54	23
2026	53	23
2027	52	24
2028	49	23
2029-2033	226	107

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, 2023:

	Pension	**Other Postretirement**
	%	%
Debt securities[(1)]	40-60	25-35
Equity securities[(1)]	30-60	65-75
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
As of December 31, 2023:				
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	$ 91	$ 141	$ —	232
Investment funds[2] measured at net asset value				284
Total assets measured at fair value				$ 516
As of December 31, 2022:				
Cash equivalents	$ —	$ 15	$ —	$ 15
Debt securities:				
U.S. government obligations	22	—	—	22
Corporate obligations	—	135	—	135
Municipal obligations	—	10	—	10
Agency, asset and mortgage-backed obligations	—	13	—	13
Equity securities:				
U.S. companies	71	—	—	71
International companies	1	—	—	1
Total assets in the fair value hierarchy	$ 94	$ 173	$ —	267
Investment funds[2] measured at net asset value				223
Total assets measured at fair value				$ 490

(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 68% and 32%, respectively, for 2023 and 55% and 45%, respectively, for 2022. Additionally, these funds are invested in U.S. and international securities of approximately 93% and 7%, respectively, for 2023 and 97% and 3%, respectively, for 2022.

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
As of December 31, 2023:				
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	$ 241	$ 37	$ —	$ 278
As of December 31, 2022:				
Cash equivalents	$ 10	$ —	$ —	$ 10
Debt securities:				
U.S. government obligations	2	—	—	2
Corporate obligations	—	3	—	3
Municipal obligations	—	22	—	22
Agency, asset and mortgage-backed obligations	—	2	—	2
Equity securities:				
Investment funds[(2)]	201	—	—	201
Total assets measured at fair value	$ 213	$ 27	$ —	$ 240

(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 83% and 17%, respectively, for 2023 and 82% and 18%, respectively, for 2022. Additionally, these funds are invested in U.S. and international securities of approximately 83% and 17%, respectively, for 2023 and 82% and 18%, respectively, for 2022.

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 $34 million, $33 million, and $27 million for the years ended December 31, 2023, 2022 and 2021, 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 $411 million and $392 million as of December 31, 2023 and 2022, respectively.

The following table presents MidAmerican Energy's ARO liabilities by asset type as of December 31 (in millions):

	2023	2022
Quad Cities Station	$ 407	$ 417
Fossil-fueled generating facilities	62	76
Wind-powered generating facilities	305	210
Solar-powered generating facilities and other	4	4
Total asset retirement obligations	$ 778	$ 707
Quad Cities Station nuclear decommissioning trust funds[1]	$ 767	$ 664

(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):

	2023	2022
Beginning balance	$ 707	$ 787
Change in estimated costs	56	(27)
Additions	3	2
Retirements	(21)	(85)
Accretion	33	30
Ending balance	$ 778	$ 707
Reflected as:		
Other current liabilities	$ 10	$ 24
Asset retirement obligations	768	683
	$ 778	$ 707

Retirements in 2023 and 2022 relate to settlements of MidAmerican Energy's coal combustion residuals ARO liabilities.

(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, 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
	$ 1,355	$ 88	$ —	$ (2)	$ 1,441
Liabilities - commodity derivatives	$ —	$ (15)	$ (11)	$ 14	$ (12)
As of December 31, 2022:					
Assets:					
Commodity derivatives	$ 1	$ 37	$ 6	$ (10)	$ 34
Money market mutual funds	225	—	—	—	225
Debt securities:					
U.S. government obligations	215	—	—	—	215
International government obligations	—	1	—	—	1
Corporate obligations	—	70	—	—	70
Municipal obligations	—	3	—	—	3
Agency, asset and mortgage-backed obligations	—	1	—	—	1
Equity securities:					
U.S. companies	360	—	—	—	360
International companies	8	—	—	—	8
Investment funds	16	—	—	—	16
	$ 825	$ 112	$ 6	$ (10)	$ 933
Liabilities - commodity derivatives	$ —	$ (12)	$ (1)	$ 10	$ (3)

(1) Represents netting under master netting arrangements and a net cash collateral receivable of $12 million and $— million as of December 31, 2023 and 2022, 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):

	2023	2022	2021
Beginning balance	$ 5	$ (5)	$ 2
Changes in fair value recognized in net regulatory assets	(40)	37	(2)
Settlements	24	(27)	(5)
Ending balance	$ (11)	$ 5	$ (5)

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):

	2023		2022	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 8,766	$ 8,252	$ 7,729	$ 6,964

(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, 2023, are as follows (in millions):

	2024	2025	2026	2027	2028	2029 and Thereafter	Total
Contract type:							
Coal and natural gas for generation	$ 123	$ 66	$ 36	$ 36	$ 6	$ —	$ 267
Electric capacity and transmission	29	29	28	17	7	—	110
Natural gas contracts for gas operations	178	102	91	64	23	14	472
Construction commitments	399	10	5	18	11	—	443
Easements	45	46	47	47	48	1,618	1,851
Maintenance, services and other	159	153	148	126	89	81	756
	$ 933	$ 406	$ 355	$ 308	$ 184	$ 1,713	$ 3,899

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 and construction of wind- and solar-powered 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. MidAmerican Energy cannot predict the ultimate outcome of these matters or the amount of refunds, if any, and accordingly, has reversed its previously accrued liability for potential refunds of amounts collected under the higher ROE during the periods covered by the complaints.

(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, 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

	For the Year Ended December 31, 2021			
	Electric	Natural Gas	Other	Total
Customer Revenue:				
Retail:				
Residential	$ 718	$ 564	$ —	$ 1,282
Commercial	327	223	—	550
Industrial	934	30	—	964
Natural gas transportation services	—	39	—	39
Other retail	149	3	—	152
Total retail	2,128	859	—	2,987
Wholesale	312	142	—	454
Multi-value transmission projects	58	—	—	58
Other Customer Revenue	—	—	15	15
Total Customer Revenue	2,498	1,001	15	3,514
Other revenue	31	2	—	33
Total operating revenue	$ 2,529	$ 1,003	$ 15	$ 3,547

(15) Shareholder's Equity

In 2023 and 2022, MidAmerican Energy paid $1,025 million and $275 million, respectively, in cash dividends to its parent company, MHC. In February 2024, MidAmerican Energy paid $425 million in a cash dividend 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):

	2023	2022	2021
Corporate-owned life insurance income (loss)	$ 23	$ (16)	$ 21
Non-service cost components of postretirement employee benefit plans	8	9	26
Interest income and other, net	5	7	6
Total	$ 36	$ —	$ 53

(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):

	2023	2022	2021
Supplemental disclosure of cash flow information:			
Interest paid, net of amounts capitalized	$ 300	$ 292	$ 279
Income taxes received, net	$ 852	$ 840	$ 746
Supplemental disclosure of non-cash investing transactions:			
Accruals related to property, plant and equipment additions	$ 193	$ 168	$ 257

(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 $94 million, $78 million and $66 million for 2023, 2022 and 2021, respectively.

MidAmerican Energy reimbursed BHE in the amount of $123 million, $79 million and $72 million in 2023, 2022 and 2021, respectively, for its share of technology costs, corporate expenses and other costs. Amounts charged to MidAmerican Energy in 2023 and 2022 were primarily reflected in construction work-in-progress on the Balance Sheets as of December 31, 2023 and 2022.

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 $141 million, $141 million and $132 million in 2023, 2022 and 2021, respectively.

MidAmerican Energy had accounts receivable from affiliates of $9 million and $9 million as of December 31, 2023 and 2022, respectively, that are included in other current assets on the Balance Sheets. MidAmerican Energy also had accounts payable to affiliates of $32 million and $22 million as of December 31, 2023 and 2022, 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 payable to BHE of $21 million and a receivable from BHE of $42 million as of December 31, 2023 and 2022, respectively. MidAmerican Energy received net cash payments for federal and state income taxes from BHE totaling $852 million, $840 million and $746 million for the years ended December 31, 2023, 2022 and 2021, 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 $82 million and $79 million as of December 31, 2023 and 2022, respectively, and are included in other assets on the Balance Sheets. Similar amounts payable to affiliates totaled $55 million and $40 million as of December 31, 2023 and 2022, 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 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, interest income, interest expense and income tax expense are allocated to each segment based on certain factors, which primarily relate to the nature of the cost. Refer to Note 9 for a discussion of items affecting income tax expense (benefit) for the regulated electric and natural gas operating segments.

The following tables provide information on a reportable segment basis (in millions):

	Years Ended December 31,		
	2023	2022	2021
Operating revenue:			
Regulated electric	$ 2,673	$ 2,988	$ 2,529
Regulated natural gas	713	1,030	1,003
Other	7	7	15
Total operating revenue	$ 3,393	$ 4,025	$ 3,547
Depreciation and amortization:			
Regulated electric	$ 846	$ 1,112	$ 861
Regulated natural gas	62	56	53
Total depreciation and amortization	$ 908	$ 1,168	$ 914
Operating income:			
Regulated electric	$ 471	$ 372	$ 358
Regulated natural gas	50	66	58
Total operating income	$ 521	$ 438	$ 416
Interest expense:			
Regulated electric	$ 320	$ 290	$ 279
Regulated natural gas	26	23	23
Total interest expense	$ 346	$ 313	$ 302

	Years Ended December 31,		
	2023	2022	2021
Income tax expense (benefit):			
Regulated electric	$ (676)	$ (779)	$ (677)
Regulated natural gas	(14)	9	3
Other	(3)	—	(1)
Total income tax expense (benefit)	$ (693)	$ (770)	$ (675)
Net income:			
Regulated electric	$ 929	$ 931	$ 844
Regulated natural gas	50	30	50
Other	3	—	—
Net income	$ 982	$ 961	$ 894
Capital expenditures:			
Regulated electric	$ 1,683	$ 1,742	$ 1,806
Regulated natural gas	149	127	106
Other	1	—	—
Total capital expenditures	$ 1,833	$ 1,869	$ 1,912

	As of December 31,		
	2023	2022	2021
Total assets:			
Regulated electric	$ 23,334	$ 22,092	$ 21,385
Regulated natural gas	1,900	1,885	1,871
Other	1	1	1
Total assets	$ 25,235	$ 23,978	$ 23,257

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, 2023 and 2022, 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, 2023, 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, 2023 and 2022, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2023, 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 audit 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 audit 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 future 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 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 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 23, 2024

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,	
	2023	**2022**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 637	$ 261
Trade receivables, net	272	536
Income tax receivable	1	43
Inventories	364	277
Prepayments	113	91
Other current assets	40	66
Total current assets	1,427	1,274
Property, plant and equipment, net	21,971	21,092
Goodwill	1,270	1,270
Regulatory assets	600	550
Investments and restricted investments	1,032	904
Other assets	209	164
Total assets	$ 26,509	$ 25,254

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,	
	2023	**2022**
LIABILITIES AND MEMBER'S EQUITY		
Current liabilities:		
Accounts payable	$ 543	$ 536
Accrued interest	112	90
Accrued property, income and other taxes	197	170
Current portion of long-term debt	539	317
Other current liabilities	102	93
Total current liabilities	1,493	1,206
Long-term debt	8,467	7,652
Regulatory liabilities	1,079	1,119
Deferred income taxes	3,492	3,431
Asset retirement obligations	768	683
Other long-term liabilities	577	484
Total liabilities	15,876	14,575
Commitments and contingencies (Note 13)		
Member's equity:		
Paid-in capital	1,679	1,679
Retained earnings	8,954	9,000
Total member's equity	10,633	10,679
Total liabilities and member's equity	$ 26,509	$ 25,254

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,		
	2023	**2022**	**2021**
Operating revenue:			
Regulated electric	$ 2,673	$ 2,988	$ 2,529
Regulated natural gas and other	720	1,037	1,018
Total operating revenue	3,393	4,025	3,547
Operating expenses:			
Cost of fuel and energy	501	679	539
Cost of natural gas purchased for resale and other	451	763	761
Operations and maintenance	851	828	775
Depreciation and amortization	908	1,168	914
Property and other taxes	161	149	142
Total operating expenses	2,872	3,587	3,131
Operating income	521	438	416
Other income (expense):			
Interest expense	(362)	(333)	(319)
Allowance for borrowed funds	19	15	13
Allowance for equity funds	59	51	39
Other, net	48	—	54
Total other income (expense)	(236)	(267)	(213)
Income before income tax expense (benefit)	285	171	203
Income tax expense (benefit)	(695)	(776)	(680)
Net income	$ 980	$ 947	$ 883

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)

	Paid-in Capital	Retained Earnings	Total Member's Equity
Balance, December 31, 2020	$ 1,679	$ 7,240	$ 8,919
Net income	—	883	883
Other equity transactions	—	(1)	(1)
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

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, 2023	2022	2021
Cash flows from operating activities:			
Net income	$ 980	$ 947	$ 883
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	908	1,168	914
Amortization of utility plant to other operating expenses	34	35	34
Allowance for equity funds	(59)	(51)	(39)
Deferred income taxes and amortization of investment tax credits	90	33	153
Settlements of asset retirement obligations	(21)	(85)	(103)
Other, net	33	52	21
Changes in other operating assets and liabilities:			
Trade receivables and other assets	254	(11)	(293)
Inventories	(87)	(43)	44
Pension and other postretirement benefit plans, net	3	8	(4)
Accrued property, income and other taxes, net	77	40	(71)
Accounts payable and other liabilities	(9)	68	66
Net cash flows from operating activities	2,203	2,161	1,605
Cash flows from investing activities:			
Capital expenditures	(1,833)	(1,869)	(1,912)
Purchases of marketable securities	(243)	(499)	(213)
Proceeds from sales of marketable securities	227	492	207
Proceeds from sales of other investments	12	—	—
Other, net	12	8	6
Net cash flows from investing activities	(1,825)	(1,868)	(1,912)
Cash flows from financing activities:			
Distributions to member	(1,025)	(69)	—
Proceeds from long-term debt	1,338	—	492
Repayments of long-term debt	(317)	(2)	(1)
Net change in note payable to affiliate	—	(189)	12
Other, net	(2)	(2)	(2)
Net cash flows from financing activities	(6)	(262)	501
Net change in cash and cash equivalents and restricted cash and cash equivalents	372	31	194
Cash and cash equivalents and restricted cash and cash equivalents at beginning of year	271	240	46
Cash and cash equivalents and restricted cash and cash equivalents at end of year	$ 643	$ 271	$ 240

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 owns subsidiaries principally engaged in energy businesses. BHE is a consolidated 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, 2023, 2022 and 2021.

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, 2023 and 2022 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,	
	2023	2022
Cash and cash equivalents	$ 637	$ 261
Restricted cash and cash equivalents in other current assets	6	10
Total cash and cash equivalents and restricted cash and cash equivalents	$ 643	$ 271

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, 2023. 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 2023, 2022 and 2021, MidAmerican Funding did not record any goodwill impairments.

New Accounting Pronouncements

In November 2023, the FASB issued 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 is currently evaluating the impact of adopting this guidance on its 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. 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, 2023 and 2022, 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, 2023 and 2022.

(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 2024 and has a variable interest rate based on the Secured Overnight Financing Rate, plus a spread. As of December 31, 2023 and 2022, there were no borrowings outstanding under this credit facility. As of December 31, 2023, 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, 2023 and 2022.

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, 2023.

As of December 31, 2023, 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):

	2023	2022	2021
Current:			
Federal	$ (756)	$ (773)	$ (739)
State	(29)	(36)	(94)
	(785)	(809)	(833)
Deferred:			
Federal	109	77	189
State	(18)	(43)	(35)
	91	34	154
Investment tax credits	(1)	(1)	(1)
Total	$ (695)	$ (776)	$ (680)

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:

	2023	2022	2021
Federal statutory income tax rate	21 %	21 %	21 %
Income tax credits	(239)	(416)	(283)
State income tax, net of federal income tax impacts	(13)	(36)	(50)
Effects of ratemaking	(12)	(26)	(21)
Other, net	(1)	3	(2)
Effective income tax rate	(244)%	(454)%	(335)%

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, 2023, 2022 and 2021 totaled $681 million, $710 million and $574 million, respectively.

MidAmerican Funding's net deferred income tax liability consists of the following as of December 31 (in millions):

	2023	2022
Deferred income tax assets:		
Regulatory liabilities	$ 218	$ 194
Asset retirement obligations	204	192
State carryforwards	68	61
Revenue sharing	34	87
Employee benefits	25	37
Other	69	24
Total deferred income tax assets	618	595
Valuation allowances	(2)	(2)
Total deferred income tax assets, net	616	593
Deferred income tax liabilities:		
Property-related items	(3,972)	(3,895)
Regulatory assets	(134)	(128)
Other	(2)	(1)
Total deferred income tax liabilities	(4,108)	(4,024)
Net deferred income tax liability	$ (3,492)	$ (3,431)

As of December 31, 2023, MidAmerican Funding's state tax carryforwards, principally related to $1 billion of net operating losses, expire at various intervals between 2024 and 2042.

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, 2019, 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):

	2023	2022
Beginning balance	$ 16	$ 13
Additions based on tax positions related to the current year	10	15
Interest	1	—
Reductions based on tax positions related to the current year	(5)	(12)
Ending balance	$ 22	$ 16

As of December 31, 2023, MidAmerican Funding had unrecognized tax benefits totaling $48 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):

	2023	2022	2021
Pension costs	$ 14	$ 8	$ 21
Other postretirement costs	2	1	2

(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):

	2023		2022	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 9,006	$ 8,515	$ 7,969	$ 7,219

(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 2023 and 2022, MidAmerican Funding paid $1,025 million and $69 million, respectively, in cash distributions to its parent company, BHE. In February 2024, MidAmerican Funding paid $425 million in a cash distribution 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):

	2023	2022	2021
Corporate-owned life insurance income (loss)	$ 23	$ (16)	$ 21
Gains on sales of assets and other investments	12	—	—
Non-service cost components of postretirement employee benefit plans	8	9	26
Interest income and other, net	5	7	7
Total	$ 48	$ —	$ 54

(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):

	2023	2022	2021
Supplemental disclosure of cash flow information:			
Interest paid, net of amounts capitalized	$ 317	$ 309	$ 296
Income taxes received, net	$ 855	$ 845	$ 751
Supplemental disclosure of non-cash investing and financing transactions:			
Accruals related to property, plant and equipment additions	$ 193	$ 168	$ 257

(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 $94 million, $77 million and $65 million for 2023, 2022 and 2021, respectively.

MidAmerican Funding reimbursed BHE in the amount of $123 million, $79 million and $72 million in 2023, 2022 and 2021, respectively, for its share of technology costs, corporate expenses and other costs. Amounts charged to MidAmerican Funding in 2023 and 2022 were primarily reflected in construction work-in-progress on the Consolidated Balance Sheets as of December 31, 2023 and 2022.

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 $141 million, $141 million and $132 million in 2023, 2022 and 2021, respectively.

MidAmerican Funding had accounts receivable from affiliates of $10 million and $10 million as of December 31, 2023 and 2022, respectively, that are included in other current assets on the Consolidated Balance Sheets. MidAmerican Funding also had accounts payable to affiliates of $32 million and $22 million as of December 31, 2023 and 2022, 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 payable to BHE of $21 million and a receivable from BHE of $43 million as of December 31, 2023 and 2022, respectively. MidAmerican Funding received net cash payments for federal and state income taxes from BHE totaling $855 million, $845 million and $751 million for the years ended December 31, 2023, 2022 and 2021, 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 $82 million and $79 million as of December 31, 2023 and 2022, respectively, and are included in other assets on the Consolidated Balance Sheets. Similar amounts payable to affiliates totaled $55 million and $40 million as of December 31, 2023 and 2022, 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 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, interest income, interest expense and income tax expense are allocated to each segment based on certain factors, which primarily relate to the nature of the cost. "Other" in the tables below consists of the nonregulated subsidiaries of MidAmerican Funding not engaged in the energy business and parent company interest expense. Refer to Note 9 for a discussion of items affecting income tax expense (benefit) for the regulated electric and natural gas operating segments.

The following tables provide information on a reportable segment basis (in millions):

	Years Ended December 31,		
	2023	2022	2021
Operating revenue:			
Regulated electric	$ 2,673	$ 2,988	$ 2,529
Regulated natural gas	713	1,030	1,003
Other	7	7	15
Total operating revenue	$ 3,393	$ 4,025	$ 3,547
Depreciation and amortization:			
Regulated electric	$ 846	$ 1,112	$ 861
Regulated natural gas	62	56	53
Total depreciation and amortization	$ 908	$ 1,168	$ 914
Operating income:			
Regulated electric	$ 471	$ 372	$ 358
Regulated natural gas	50	66	58
Total operating income	$ 521	$ 438	$ 416

	Years Ended December 31,		
	2023	2022	2021
Interest expense:			
Regulated electric	$ 320	$ 290	$ 279
Regulated natural gas	26	23	23
Other	16	20	17
Total interest expense	$ 362	$ 333	$ 319
Income tax expense (benefit):			
Regulated electric	$ (676)	$ (779)	$ (677)
Regulated natural gas	(14)	9	3
Other	(5)	(6)	(6)
Total income tax expense (benefit)	$ (695)	$ (776)	$ (680)
Net income:			
Regulated electric	$ 929	$ 931	$ 844
Regulated natural gas	50	30	50
Other	1	(14)	(11)
Net income	$ 980	$ 947	$ 883
Capital expenditures:			
Regulated electric	$ 1,683	$ 1,742	$ 1,806
Regulated natural gas	149	127	106
Other	1	—	—
Total capital expenditures	$ 1,833	$ 1,869	$ 1,912

	As of December 31,		
	2023	2022	2021
Total assets:			
Regulated electric	$ 24,525	$ 23,283	$ 22,576
Regulated natural gas	1,979	1,963	1,950
Other	5	8	5
Total assets	$ 26,509	$ 25,254	$ 24,531

Goodwill by reportable segment as of December 31, 2023 and 2022, was as follows (in millions):

Regulated electric	$ 1,191
Regulated natural gas	79
Total	$ 1,270

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, 2023 was $260 million, a decrease of $38 million, or 13%, compared to 2022, primarily due to lower utility margin, higher interest expense, mainly due to higher long-term debt at a higher average interest rate, higher depreciation and amortization, primarily due to higher plant placed in-service, and higher operations and maintenance expenses. The decrease is partially offset by higher capitalized interest and allowance for equity funds, mainly due to higher construction work-in-progress, favorable interest and dividend income, primarily from carrying charges on regulatory balances, lower income tax expense, mainly due to lower pretax income and the effects of ratemaking, 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. Operations and maintenance expenses increased primarily due to 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. 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%.

Net income for the year ended December 31, 2022 was $298 million, a decrease of $5 million, or 2%, compared to 2021, primarily due to lower cash surrender value of corporate-owned life insurance policies and higher pension expense, higher interest expense, primarily due to higher long-term debt, higher depreciation and amortization, mainly due to higher plant placed in-service, higher property and other taxes, mainly due to a decrease in the amount of abatements available, higher operations and maintenance expenses, mainly due to higher earnings sharing and higher plant operations and maintenance expenses, partially offset by higher interest and dividend income, primarily from carrying charges on regulatory balances, higher capitalized interest and allowance for funds used during construction from higher construction work-in-progress and higher utility margin. Utility margin increased primarily due to higher regulatory-related revenue deferrals and higher retail customer volumes, partially offset by unfavorable price impacts from changes in sales mix, lower transmission and wholesale revenue and lower other retail revenue. Retail customer volumes, including distribution only service customers, increased 1.9% primarily due to an increase in the average number of customers and favorable changes in customer usage, offset by the unfavorable impact of weather. Energy generated decreased 4% for 2022 compared to 2021 primarily due to lower natural gas-fueled generation. Wholesale electricity sales volumes increased 65% and purchased electricity volumes increased 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 profitability 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 running 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):

	2023	2022	Change		2022	2021	Change	
Utility margin:								
Operating revenue	$ 3,088	$ 2,630	$ 458	17 %	$ 2,630	$ 2,139	$ 491	23 %
Cost of fuel and energy	1,942	1,427	515	36	1,427	939	488	52
Utility margin	1,146	1,203	(57)	(5)	1,203	1,200	3	—
Operations and maintenance	312	303	9	3	303	301	2	1
Depreciation and amortization	432	417	15	4	417	406	11	3
Property and other taxes	56	53	3	6	53	48	5	10
Operating income	$ 346	$ 430	$ (84)	(20)%	$ 430	$ 445	$ (15)	(3)%

Utility Margin

A comparison of key operating results related to utility margin is as follows for the years ended December 31:

	2023	2022	Change		2022	2021	Change	
Utility margin (in millions):								
Operating revenue	$ 3,088	$ 2,630	$ 458	17 %	$ 2,630	$ 2,139	$ 491	23 %
Cost of fuel and energy	1,942	1,427	515	36	1,427	939	488	52
Utility margin	$ 1,146	$ 1,203	$ (57)	(5)%	$ 1,203	$ 1,200	$ 3	— %
Sales (GWhs):								
Residential	9,584	10,299	(715)	(7)%	10,299	10,415	(116)	(1)%
Commercial	4,807	4,904	(97)	(2)	4,904	4,838	66	1
Industrial	5,827	5,630	197	3	5,630	5,270	360	7
Other	179	191	(12)	(6)	191	198	(7)	(4)
Total fully bundled[1]	20,397	21,024	(627)	(3)	21,024	20,721	303	1
Distribution only service	2,831	2,786	45	2	2,786	2,646	140	5
Total retail	23,228	23,810	(582)	(2)	23,810	23,367	443	2
Wholesale	230	586	(356)	(61)	586	356	230	65
Total GWhs sold	23,458	24,396	(938)	(4)%	24,396	23,723	673	3 %
Average number of retail customers (in thousands)	1,015	1,001	14	1 %	1,001	985	16	2 %
Average revenue per MWh:								
Retail - fully bundled[1]	$147.38	$120.21	$ 27.17	23 %	$120.21	$ 98.62	$ 21.59	22 %
Wholesale	$ 62.73	$ 61.83	$ 0.90	1 %	$ 61.83	$ 60.69	$ 1.14	2 %
Heating degree days	1,962	1,904	58	3 %	1,904	1,613	291	18 %
Cooling degree days	3,651	4,016	(365)	(9)%	4,016	4,109	(93)	(2)%
Sources of energy (GWhs)[2][3]:								
Natural gas	13,719	13,068	651	5 %	13,068	13,655	(587)	(4)%
Renewables	66	69	(3)	(4)	69	65	4	6
Total energy generated	13,785	13,137	648	5	13,137	13,720	(583)	(4)
Energy purchased	7,606	8,830	(1,224)	(14)	8,830	7,778	1,052	14
Total	21,391	21,967	(576)	(3)%	21,967	21,498	469	2 %
Average cost of energy per MWh[2][4]:								
Energy generated	$ 65.25	$ 49.82	$ 15.42	31 %	$ 49.82	$ 24.41	$ 25.41	104 %
Energy purchased	$137.08	$ 87.49	$ 49.59	57 %	$ 87.49	$ 77.64	$ 9.85	13 %

(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 846, 1,113 and 1,389 GWhs of natural gas generated energy that is purchased at cost by related parties for the years ended December 31, 2023, 2022 and 2021, 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, 2023 Compared to Year Ended December 31, 2022

Utility margin decreased $57 million, or 5%, 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.

Year Ended December 31, 2022 Compared to Year Ended December 31, 2021

Utility margin increased $3 million for 2022 compared to 2021 primarily due to:

- $11 million of higher regulatory-related revenue deferrals and
- $4 million of higher electric retail utility margin due to higher retail customer volumes, offset by unfavorable price impacts from changes in sales mix. Retail customer volumes, including distribution only service customers, increased 1.9% primarily due to an increase in the average number of customers and favorable changes in customer usage, offset by the unfavorable impact of weather.

The increase in utility margin was partially offset by:

- $6 million of lower energy efficiency program rates (offset in operations and maintenance expense);
- $3 million of lower transmission and wholesale revenue; and;
- $3 million due to lower other retail revenue.

Operations and maintenance increased $2 million, or 1%, for 2022 compared to 2021 primarily due to higher earnings sharing and higher plant operations and maintenance expenses, partially offset by lower energy efficiency program costs (offset in operating revenue).

Depreciation and amortization increased $11 million, or 3%, for 2022 compared to 2021 primarily due to higher plant placed in-service.

Property and other taxes increased $5 million, or 10%, for 2022 compared to 2021 primarily due to a decrease in the amount of abatements available.

Interest expense increased $12 million, or 8% for 2022 compared to 2021 primarily due to higher long-term debt.

Capitalized interest increased $5 million for 2022 compared to 2021 primarily due to higher construction work-in-progress.

Allowance for equity funds increased $4 million, or 57%, for 2022 compared to 2021 primarily due to higher construction work-in-progress.

Interest and dividend income increased $27 million for 2022 compared to 2021 primarily due to higher interest income, mainly from carrying charges on regulatory balances.

Other, net decreased $15 million, or 83%, for 2022 compared to 2021 primarily due to lower cash surrender value of corporate-owned life insurance policies and higher pension expense.

Liquidity and Capital Resources

As of December 31, 2023, Nevada Power's total net liquidity was $620 million as follows (in millions):

Cash and cash equivalents	$ 20
Credit facilities[(1)]	600
Total net liquidity	$ 620
Credit facilities:	
Maturity dates	2026

(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, 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.

Net cash flows from operating activities for the years ended December 31, 2022 and 2021 were $355 million and $505 million, respectively. The change was primarily due to higher payments related to fuel and energy costs and the timing of payments for operating costs, partially offset by higher collections from customers and lower payments for income taxes.

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, 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.

Net cash flows from investing activities for the years ended December 31, 2022 and 2021 were $(862) million and $(447) million, respectively. The change was primarily due to increased capital expenditures and the issuance of 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, 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.

Net cash flows from financing activities for the years ended December 31, 2022 and 2021 were $522 million and $(49) million, respectively. The change was primarily due to higher proceeds from the issuance of long-term debt, lower dividends paid to NV Energy, Inc. and higher contributions from NV Energy, Inc., partially offset by higher repayments of short-term debt.

In February 2024, Nevada Power received a contribution from NV Energy, Inc. of $50 million.

Ability to Issue Debt

Nevada Power currently has an effective shelf registration statement with the SEC to issue an additional $2.1 billion of general and refunding mortgage securities through November 1, 2025. Additionally, Nevada Power's ability to issue debt is primarily impacted by its financing authority from the PUCN. As of December 31, 2023, 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 $3.8 billion and to issue common and preferred stock so long as the total amounts outstanding do not exceed $4.1 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, 2023. 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.

Ability to Issue 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, 2023, $10.3 billion of Nevada Power's assets were pledged. Nevada Power had the capacity to issue $3.2 billion of additional general and refunding mortgage securities as of December 31, 2023, 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.

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		
	2021	**2022**	**2023**	**2024**	**2025**	**2026**
Electric distribution	$ 184	$ 236	$ 352	$ 316	$ 282	$ 294
Electric transmission	57	110	124	237	469	556
Solar generation	8	85	188	58	195	332
Electric battery storage	—	8	338	183	189	592
Other	200	323	407	372	162	241
Total	$ 449	$ 762	$ 1,409	$ 1,166	$ 1,297	$ 2,015

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 2024 through 2026. 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. The Nevada Utilities have received approval from the PUCN to build 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 Robinson Summit substation, near Ely, Nevada. 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 that will be developed in Clark County, Nevada. Commercial operation is expected by early 2024. The second growth project, pending PUCN approval, consists of 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 between Nevada Power and Sierra Pacific to be approved by the PUCN. Commercial operation of the solar is expected by early 2027.

- Electric battery storage includes three growth projects and other planned electric battery storage systems. The first project consists of 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. Commercial operation was reached in December of 2023. The second growth project consists of a 100-MW battery energy storage system co-located with a 150-MW solar photovoltaic facility that will be developed in Clark County, Nevada. Commercial operation is expected by early 2024. The third growth project, pending PUCN approval, consists of a 400-MW battery energy storage system co-located with a 400MW solar photovoltaic facility that would be developed in Churchill County, Nevada with ownership share between Nevada Power and Sierra Pacific to be approved by the PUCN. Commercial operation of the battery energy storage system is expected by early 2026.
- 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 are under development at the Silverhawk generating facility in Clark County, Nevada. Commercial operation is expected by the third quarter of 2024. Operating expenditures consist of turbine upgrades at several generating facilities, 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 seeks, in part (1) to convert the existing coal fueled plant at North Valmy Generating Station to a cleaner natural gas fueled plant (2) to construct 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 a 149 MW photovoltaic and 149 MW battery energy storage system known as the 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 Nevada Power's share is approximately $1.0 billion with an order expected in 2024.

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 $3.2 billion on long-term debt, including $168 million due in 2024.

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, 2023, 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, 2023, Nevada Power would have been required to post $68 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 $1.1 billion and total regulatory liabilities were $1.1 billion as of December 31, 2023. 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, 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 2017 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, 2023, these amounts were recognized as a net regulatory liability of $525 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, 2023:			
Total commodity derivative contracts	$ (68)	$ (61)	$ (75)
As of December 31, 2022:			
Total commodity derivative contracts	$ (52)	$ (23)	$ (81)

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, 2023 and 2022, a net regulatory asset of $68 million and $52 million, respectively, was recorded related to the net derivative liability of $68 million and $52 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, 2023 and 2022, Nevada Power had short- and long-term variable-rate obligations totaling $— million and $300 million, respectively, that expose Nevada Power 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 Nevada Power's annual interest expense. The carrying value of the variable-rate obligations approximates fair value as of December 31, 2023 and 2022.

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, 2023, 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

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, 2023 and 2022, 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, 2023, 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, 2023 and 2022, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2023, 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 audit 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 future 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 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 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 23, 2024

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,	
	2023	2022
ASSETS		
Current assets:		
Cash and cash equivalents	$ 20	$ 43
Trade receivables, net	374	388
Note receivable from affiliate	—	100
Inventories	129	93
Regulatory assets	586	666
Other current assets	63	89
Total current assets	1,172	1,379
Property, plant and equipment, net	8,658	7,406
Regulatory assets	499	628
Other assets	398	388
Total assets	$ 10,727	$ 9,801
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities:		
Accounts payable	$ 466	$ 422
Accrued interest	44	40
Accrued property, income and other taxes	65	32
Regulatory liabilities	43	45
Customer deposits	59	51
Derivative contracts	62	51
Other current liabilities	48	49
Total current liabilities	787	690
Long-term debt	3,392	3,195
Finance lease obligations	279	295
Regulatory liabilities	1,017	1,093
Deferred income taxes	836	875
Other long-term liabilities	452	299
Total liabilities	6,763	6,447
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	2,733	2,333
Retained earnings	1,232	1,022
Accumulated other comprehensive loss, net	(1)	(1)
Total shareholder's equity	3,964	3,354
Total liabilities and shareholder's equity	$ 10,727	$ 9,801

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,		
	2023	2022	2021
Operating revenue	$ 3,088	$ 2,630	$ 2,139
Operating expenses:			
Cost of fuel and energy	1,942	1,427	939
Operations and maintenance	312	303	301
Depreciation and amortization	432	417	406
Property and other taxes	56	53	48
Total operating expenses	2,742	2,200	1,694
Operating income	346	430	445
Other income (expense):			
Interest expense	(196)	(165)	(153)
Capitalized interest	25	8	3
Allowance for equity funds	21	11	7
Interest and dividend income	72	47	20
Other, net	14	3	18
Total other income (expense)	(64)	(96)	(105)
Income before income tax expense	282	334	340
Income tax expense	22	36	37
Net income	$ 260	$ 298	$ 303

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 Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss, Net	Total Shareholder's Equity
	Shares	Amount				
Balance, December 31, 2020	1,000	$ —	$ 2,308	$ 634	$ (3)	$ 2,939
Net income	—	—	—	303	—	303
Dividends declared	—	—	—	(213)	—	(213)
Other equity transactions	—	—	—	—	1	1
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

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,		
	2023	**2022**	**2021**
Cash flows from operating activities:			
Net income	$ 260	$ 298	$ 303
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	432	417	406
Allowance for equity funds	(21)	(11)	(7)
Deferred energy	14	(541)	(245)
Amortization of deferred energy	40	160	11
Other changes in regulatory assets and liabilities	(13)	(15)	(19)
Deferred income taxes and amortization of investment tax credits	26	49	—
Other, net	(1)	8	—
Changes in other operating assets and liabilities:			
Trade receivables and other assets	(3)	(178)	6
Inventories	(36)	(29)	5
Accrued property, income and other taxes	39	21	(18)
Accounts payable and other liabilities	24	176	63
Net cash flows from operating activities	761	355	505
Cash flows from investing activities:			
Capital expenditures	(1,409)	(762)	(449)
Net proceeds from (issuance of) affiliate note receivable	100	(100)	—
Other, net	—	—	2
Net cash flows from investing activities	(1,309)	(862)	(447)
Cash flows from financing activities:			
Proceeds from long-term debt	494	694	—
Repayments of long-term debt	(300)	—	—
Net (repayments of) proceeds from short-term debt	—	(180)	180
Dividends paid	(50)	—	(213)
Contributions from parent	400	25	—
Other, net	(19)	(17)	(16)
Net cash flows from financing activities	525	522	(49)
Net change in cash and cash equivalents and restricted cash and cash equivalents	(23)	15	9
Cash and cash equivalents and restricted cash and cash equivalents at beginning of period	60	45	36
Cash and cash equivalents and restricted cash and cash equivalents at end of period	$ 37	$ 60	$ 45

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 owns subsidiaries principally engaged in energy businesses. BHE is a consolidated 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, 2023, 2022 and 2021.

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 PUCN for a certain renewable energy contract. A reconciliation of cash and cash equivalents and restricted cash and cash equivalents as of December 31, 2023 and December 31, 2022, 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,	
	2023	2022
Cash and cash equivalents	$ 20	$ 43
Restricted cash and cash equivalents included in other current assets	17	17
Total cash and cash equivalents and restricted cash and cash equivalents	$ 37	$ 60

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):

	2023	2022	2021
Beginning balance	$ 20	$ 18	$ 19
Charged to operating costs and expenses, net	18	14	13
Write-offs, net	(18)	(12)	(14)
Ending balance	$ 20	$ 20	$ 18

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 \$129 million and \$93 million as of December 31, 2023 and 2022. 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 Public Utilities Commission of Nevada ("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 asset or liability.

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 2023 and 2022 was 6.95% and 6.55%, 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, 2023 and 2022, trade receivables, net on the Consolidated Balance Sheets relate substantially to Customer Revenue, including unbilled revenue of $151 million and $143 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 $3 million and $4 million as of December 31, 2023 and 2022, 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 on the Consolidated Statements of Operations.

Segment Information

Nevada Power currently has one segment, which includes its regulated electric utility operations.

New Accounting Pronouncements

In November 2023, the FASB issued 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 is currently evaluating the impact of adopting this guidance on its 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. 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	2023	2022
Utility plant:			
Generation	30 - 55 years	$ 4,476	$ 3,977
Transmission	45 - 70 years	1,590	1,562
Distribution	20 - 65 years	4,451	4,134
General and intangible plant	5 - 65 years	906	871
		11,423	10,544
Accumulated depreciation and amortization		(3,856)	(3,624)
Utility plant, net		7,567	6,920
Nonregulated, net of accumulated depreciation and amortization	45 years	1	1
		7,568	6,921
Construction work-in-progress		1,090	485
Property, plant and equipment, net		$ 8,658	$ 7,406

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, 2023, 2022 and 2021 was 3.1%, 3.1%, and 3.2%, 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.

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, 2023 (dollars in millions):

	Nevada Power's Share	Utility Plant	Accumulated Depreciation	Construction Work-in-Progress
Navajo Generating Station[(1)]	11 %	$ —	$ 2	$ —
ON Line Transmission Line	19	129	28	1
Other transmission facilities	Various	60	28	1
Total		$ 189	$ 58	$ 2

(1) Represents Nevada Power's proportionate share of capitalized asset retirement costs to retire the Navajo Generating Station, which was shut down in November 2019.

(5) Leases

The following table summarizes Nevada Power's leases recorded on the Consolidated Balance Sheet as of December 31 (in millions):

	2023	2022
Right-of-use assets:		
Operating leases	$ 7	$ 9
Finance leases	289	303
Total right-of-use assets	$ 296	$ 312
Lease liabilities:		
Operating leases	$ 9	$ 11
Finance leases	298	313
Total lease liabilities	$ 307	$ 324

The following table summarizes Nevada Power's lease costs for the years ended December 31 (in millions):

	2023	2022	2021
Variable	$ 264	$ 369	$ 449
Operating	2	2	2
Finance:			
Amortization	15	14	13
Interest	26	27	28
Total lease costs	$ 307	$ 412	$ 492
Weighted-average remaining lease term (years):			
Operating leases	3.7	4.8	5.7
Finance leases	28.2	29.1	28.7
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):

	2023	2022	2021
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	(26)	(28)	(29)
Financing cash flows from finance leases	(18)	(17)	(16)
Right-of-use assets obtained in exchange for lease liabilities:			
Operating leases	$ 1	$ —	$ —
Finance leases	4	3	1

Nevada Power has the following remaining lease commitments as of December 31, 2023 (in millions):

	Operating	Finance	Total
2024	$ 3	$ 45	$ 48
2025	3	44	47
2026	3	44	47
2027	2	42	44
2028	—	39	39
Thereafter	—	377	377
Total undiscounted lease payments	11	591	602
Less - amounts representing interest	(2)	(293)	(295)
Lease liabilities	$ 9	$ 298	$ 307

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 $264 million and $276 million were included on the Consolidated Balance Sheets as of December 31, 2023 and 2022, 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	2023	2022
Deferred energy costs	1 year	$ 575	$ 654
Merger costs from 1999 merger	21 years	100	105
Asset retirement obligations	7 years	69	69
Unrealized loss on regulated derivative contracts	1 year	68	75
Decommissioning costs	3 years	56	116
Deferred operating costs	18 years	41	67
Other	Various	176	208
Total regulatory assets		$ 1,085	$ 1,294
Reflected as:			
Current assets		$ 586	$ 666
Noncurrent assets		499	628
Total regulatory assets		$ 1,085	$ 1,294

Nevada Power had regulatory assets not earning a return on investment of $299 million and $320 million as of December 31, 2023 and 2022, 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	2023	2022
Deferred income taxes[1]	Various	$ 525	$ 560
Cost of removal[2]	30 years	368	358
Earning sharing mechanism	3 years	115	114
Other	Various	52	106
Total regulatory liabilities		$ 1,060	$ 1,138
Reflected as:			
Current liabilities		$ 43	$ 45
Noncurrent liabilities		1,017	1,093
Total regulatory liabilities		$ 1,060	$ 1,138

(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 prudency 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 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 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.

(7) Short-term Debt and Credit Facilities

Nevada Power has a $600 million secured credit facility expiring in June 2026 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, 2023 and 2022, 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, 2023, Nevada Power had $50 million of letter of credit capacity under its $600 million secured credit facility, of which no amount was outstanding.

As of December 31, 2022, Nevada Power had $100 million of letter of credit capacity under its $400 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	2023	2022
General and refunding mortgage securities:			
3.700% Series CC, due 2029	$ 500	$ 498	$ 497
2.400% Series DD, due 2030	425	423	422
6.650% Series N, due 2036	367	360	360
6.750% Series R, due 2037	349	346	346
5.375% Series X, due 2040	250	248	248
5.450% Series Y, due 2041	250	240	239
3.125% Series EE, due 2050	300	298	298
5.900% Series GG, due 2053	400	394	394
6.000% Series 2023A, due 2054	500	494	—
Tax-exempt refunding revenue bond obligations:			
Fixed-rate series:			
4.125% Pollution Control Bonds Series 2017A, due 2032(1)	40	39	39
3.750% Pollution Control Bonds Series 2017, due 2036(1)	40	39	39
3.750% Pollution Control Bonds Series 2017B, due 2039(1)	13	13	13
Variable-rate 4.821% Term Loan, due 2024(2)	—	—	300
Total long-term debt	$ 3,434	$ 3,392	$ 3,195
Reflected as:			
Total long-term debt		$ 3,392	$ 3,195

(1) Subject to mandatory purchase by Nevada Power in March 2026 at which date the interest rate may be adjusted.

(2) Amounts borrowed under the facility bear interest at variable rates based on SOFR or a base rate, at Nevada Power's option, plus a pricing margin.

Annual Payment on Long-Term Debt

The annual repayments of long-term debt for the years beginning January 1, 2024 and thereafter, are as follows (in millions):

2029 and thereafter	$ 3,434
Total	3,434
Unamortized premium, discount and debt issuance cost	(42)
Total	$ 3,392

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, 2023, approximately $10.3 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):

	2023	2022	2021
Current – Federal	$ (4)	$ (13)	$ 37
Deferred – Federal	(74)	49	—
Investment tax credits	100	—	—
Total income tax expense	$ 22	$ 36	$ 37

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:

	2023	2022	2021
Federal statutory income tax rate	21 %	21 %	21 %
Effects of ratemaking	(13)	(11)	(11)
Other	—	1	1
Effective income tax rate	8 %	11 %	11 %

The net deferred income tax liability consists of the following as of December 31 (in millions):

	2023	2022
Deferred income tax assets:		
Regulatory liabilities	$ 195	$ 186
Operating and finance leases	66	68
Customer advances	38	27
Unamortized contract value	14	20
Other	9	9
Total deferred income tax assets	322	310
Deferred income tax liabilities:		
Property-related items	(828)	(821)
Regulatory assets	(245)	(273)
Operating and finance leases	(62)	(65)
Other	(23)	(26)
Total deferred income tax liabilities	(1,158)	(1,185)
Net deferred income tax liability	$ (836)	$ (875)

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, 2023, 2022 and 2021. Nevada Power contributed $1 million to the Non-Qualified Pension Plans for the years ended December 31, 2023, 2022 and 2021. Nevada Power did not make any contributions to the Other Postretirement Plans for the years ended December 31, 2023, 2022 and 2021. 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):

	2023	2022
Qualified Pension Plan -		
Other non-current assets	$ 38	$ 27
Non-Qualified Pension Plans:		
Other current liabilities	(1)	(1)
Other long-term liabilities	(6)	(6)
Other Postretirement Plans -		
Other non-current assets	10	7

(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 $368 million and $358 million as of December 31, 2023 and 2022, respectively.

The following table presents Nevada Power's ARO liabilities by asset type as of December 31 (in millions):

	2023	2022
Waste water remediation	$ 33	$ 31
Evaporative ponds and dry ash landfills	12	14
Solar-powered generating facilities	6	3
Other	11	11
Total asset retirement obligations	$ 62	$ 59

The following table reconciles the beginning and ending balances of Nevada Power's ARO liabilities for the years ended December 31 (in millions):

	2023	2022
Beginning balance	$ 59	$ 68
Change in estimated costs	6	5
Additions	3	—
Retirements	(9)	(16)
Accretion	3	2
Ending balance	$ 62	$ 59
Reflected as:		
Other current liabilities	$ 9	$ 16
Other long-term liabilities	53	43
	$ 62	$ 59

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.

(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, 2023:				
Not designated as hedging contracts [1]**:**				
Commodity liabilities	$ —	$ (62)	$ (6)	$ (68)
As of December 31, 2022:				
Not designated as hedging contracts [1]**:**				
Commodity assets	$ 23	$ —	$ —	$ 23
Commodity liabilities	—	(51)	(24)	(75)
Total derivative - net basis	$ 23	$ (51)	$ (24)	$ (52)

(1) Nevada Power's commodity derivatives not designated as hedging contracts are included in regulated rates. As of December 31, 2023 and 2022, a regulatory asset of $68 million and $52 million, respectively, was recorded related to the net derivative liability of $68 million and $52 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	2023	2022
Electricity purchases	Megawatt hours	1	2
Natural gas purchases	Decatherms	132	109

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, 2023, 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 $7 million and $5 million as of December 31, 2023 and 2022, 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, 2023:				
Assets:				
Money market mutual funds	$ 10	$ —	$ —	$ 10
Investment funds	4	—	—	4
	$ 14	$ —	$ —	$ 14
Liabilities - commodity derivatives	$ —	$ —	$ (68)	$ (68)
As of December 31, 2022:				
Assets:				
Commodity derivatives	$ —	$ —	$ 23	$ 23
Money market mutual funds	34	—	—	34
Investment funds	3	—	—	3
	$ 37	$ —	$ 23	$ 60
Liabilities - commodity derivatives	$ —	$ —	$ (75)	$ (75)

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, 2023, 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 or liabilities measured at fair value on a recurring basis using significant Level 3 inputs for the years ended December 31 (in millions):

	2023	2022	2021
Beginning balance	$ (52)	$ (113)	$ 15
Changes in fair value recognized in regulatory assets or liabilities	(166)	(68)	(90)
Settlements	150	129	(38)
Ending balance	$ (68)	$ (52)	$ (113)

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):

	2023		2022	
	Carrying Value	**Fair Value**	**Carrying Value**	**Fair Value**
Long-term debt	$ 3,392	$ 3,417	$ 3,195	$ 3,114

(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, 2023 are as follows (in millions):

	2024	2025	2026	2027	2028	2029 and Thereafter	Total
Contract type:							
Purchased electricity contracts - commercially operable	$ 328	$ 304	$ 306	$ 308	$ 286	$ 2,806	$ 4,338
Purchased electricity contracts - non-commercially operable	92	122	126	126	125	2,376	2,967
Fuel contracts	55	54	54	53	47	124	387
Construction commitments	248	76	41	16	9	28	418
Transmission	8	8	12	10	5	36	79
Easements	4	2	1	1	1	31	40
Maintenance, service and other contracts	25	36	36	19	1	—	117
Total commitments	$ 760	$ 602	$ 576	$ 533	$ 474	$ 5,401	$ 8,346

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 2024 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 planned 150-MW solar photovoltaic facility with an additional 100 MWs of co-located battery storage that will be developed in Clark County, Nevada, the planned Greenlink Nevada transmission expansion program that will be developed in western and northern Nevada, a planned 444 MWs of peaking combustion turbines that will be developed at the Silverhawk generating facility in Clark County, 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, 2023, 2022 and 2021.

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 2038.

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. Plaintiffs occasionally seek punitive or exemplary damages. Nevada Power does not believe that such normal and routine litigation will have a material impact on its consolidated financial results. Nevada Power is also involved in other kinds of legal actions, some of which assert or may assert claims or seek to impose fines, penalties and other costs in substantial amounts.

(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):

	2023	2022	2021
Customer Revenue:			
Retail:			
Residential	$ 1,633	$ 1,440	$ 1,207
Commercial	647	525	414
Industrial	689	528	386
Other	23	14	14
Total fully bundled	2,992	2,507	2,021
Distribution-only service	14	20	22
Total retail	3,006	2,527	2,043
Wholesale, transmission and other	63	82	74
Total Customer Revenue	3,069	2,609	2,117
Other revenue	19	21	22
Total operating revenue	$ 3,088	$ 2,630	$ 2,139

(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):

	2023	2022	2021
Supplemental disclosure of cash flow information:			
Interest paid, net of amounts capitalized	$ 159	$ 121	$ 115
Income taxes (refunded) paid	$ (52)	$ (29)	$ 63
Supplemental disclosure of non-cash investing and financing transactions:			
Accruals related to property, plant and equipment additions	$ 230	$ 98	$ 53

(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 $55 million, $46 million and $30 million for the years ended December 31, 2023, 2022 and 2021, respectively. Amounts charged to Nevada Power in 2023 and 2022 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 $50 million, $49 million, $52 million for the years ended December 31, 2023, 2022 and 2021, respectively. As of December 31, 2023 and 2022, Nevada Power's Consolidated Balance Sheets included amounts due to Kern River Gas Transmission Company of $4 million and $3 million, respectively.

Nevada Power provided electricity and other services to PacifiCorp, an indirect subsidiary of BHE, of $1 million, $4 million and $3 million for the years ended December 31, 2023, 2022 and 2021, respectively. There were no receivables associated with these services as of December 31, 2023 and 2022.

Nevada Power provided electricity to Sierra Pacific of $230 million, $362 million and $179 million for the years ended December 31, 2023, 2022 and 2021, respectively. Receivables associated with these transactions were $10 million and $41 million as of December 31, 2023 and 2022, respectively. Nevada Power purchased electricity from Sierra Pacific of $70 million, $86 million and $43 million for the years ended December 31, 2023, 2022 and 2021, respectively. Payables associated with these transactions were $1 million and $5 million as of December 31, 2023 and 2022, respectively.

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 $4 million, $3 million and $1 million for each of the years ending December 31, 2023, 2022 and 2021, respectively. NV Energy provided services to Nevada Power of $9 million for the years ending December 31, 2023, 2022 and 2021. Nevada Power provided services to Sierra Pacific of $28 million, $25 million and $25 million for the years ended December 31, 2023, 2022 and 2021, respectively. Sierra Pacific provided services to Nevada Power of $19 million, $16 million and $15 million for the years ended December 31, 2023, 2022 and 2021, respectively. As of December 31, 2023 and 2022, Nevada Power's Consolidated Balance Sheets included amounts due to NV Energy of $82 million and $51 million, respectively. There were no receivables due from NV Energy as of December 31, 2023 and 2022. In November 2022, Nevada Power entered into a $100 million unsecured note with NV Energy receivable upon demand and $— million and $100 million was outstanding as of December 31, 2023 and 2022, respectively. As of December 31, 2023 and 2022, Nevada Power's Consolidated Balance Sheets included receivables due from Sierra Pacific of $— million and $33 million, respectively. There were $20 million and $— million payables due to Sierra Pacific as of December 31, 2023 and 2022.

Nevada Power is party to a tax-sharing agreement with NV Energy and NV Energy is part of the Berkshire Hathaway consolidated U.S. federal income tax return. Federal income taxes payable to NV Energy were $31 million as of December 31, 2023 and federal income taxes receivable from NV Energy were $12 million as of December 31, 2022. Nevada Power received cash refunds of $52 million and $29 million for federal income taxes for the years ended December 31, 2023 and 2022, respectively and made cash payments of $63 million for federal income taxes for the year ended December 31, 2021.

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, 2023 was $117 million, a decrease of $1 million, or 1%, compared to 2022, primarily due to higher depreciation and amortization, mainly due to increased plant placed in-service and higher regulatory amortizations, higher operations and maintenance expenses and higher interest expense, mainly due to higher long-term debt at a higher average interest rates. The decrease is partially offset by higher utility margin, higher allowances for borrowed and equity funds, primarily due to increased construction work-in-progress, higher interest and dividend income, mainly from carrying charges on regulatory balances, lower income tax expense, mainly 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. Operations and maintenance expenses increased primarily due to increased plant operations and maintenance expenses, higher insurance premiums due to additional wildfire coverage and higher customer service operations expenses. 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%.

Net income for the year ended December 31, 2022 was $118 million, a decrease of $6 million, or 5%, compared to 2021, primarily due to higher operations and maintenance expenses, mainly due to higher plant operations and maintenance expenses, lower other, net, mainly due to higher pension expense and lower cash surrender value of corporate-owned life insurance policies, higher depreciation and amortization, primarily due to higher plant in-service, higher interest expense mainly due to higher long-term debt, partially offset by higher electric utility margin and higher interest and dividend income, mainly from carrying charges on regulatory balances. Electric utility margin increased primarily due to higher transmission and wholesale revenue, higher customer volumes and higher regulatory-related revenue deferrals, partially offset by unfavorable price impacts from changes in sales mix. Electric retail customer volumes, including distribution only service customers, increased 2.8% primarily due to an increase in the average number of customers, offset by the unfavorable impact of weather and unfavorable changes in customer usage. Energy generated decreased 13% for 2022 compared to 2021 primarily due to lower natural gas- and coal-fueled generation. Wholesale electricity sales volumes increased 13% and purchased electricity volumes decreased 5%.

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 explains profitability 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 running 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):

	2023	2022	Change		2022	2021	Change	
Electric utility margin:								
Operating revenue	$ 1,194	$ 1,025	$ 169	16 %	$ 1,025	$ 848	$ 177	21 %
Cost of fuel and energy	689	555	134	24	555	407	148	36
Electric utility margin	505	470	35	7 %	470	441	29	7 %
Natural gas utility margin:								
Operating revenue	237	168	69	41 %	168	117	51	44 %
Natural gas purchased for resale	176	111	65	59	111	61	50	82
Natural gas utility margin	61	57	4	7 %	57	56	1	2 %
Utility margin	566	527	39	7 %	527	497	30	6 %
Operations and maintenance	204	189	15	8 %	189	163	26	16 %
Depreciation and amortization	185	149	36	24	149	143	6	4
Property and other taxes	25	24	1	4	24	24	—	—
Operating income	$ 152	$ 165	$ (13)	(8)%	$ 165	$ 167	$ (2)	(1)%

Electric Utility Margin

A comparison of key operating results related to electric utility margin is as follows for the years ended December 31:

	2023	2022	Change		2022	2021	Change	
Utility margin (in millions):								
Operating revenue	$ 1,194	$ 1,025	$ 169	16 %	$ 1,025	$ 848	$ 177	21 %
Cost of fuel and energy	689	555	134	24	555	407	148	36
Utility margin	$ 505	$ 470	$ 35	7 %	$ 470	$ 441	$ 29	7 %
Sales (GWhs):								
Residential	2,655	2,747	(92)	(3)%	2,747	2,769	(22)	(1)%
Commercial	2,998	3,124	(126)	(4)	3,124	3,056	68	2
Industrial	2,684	2,867	(183)	(6)	2,867	3,716	(849)	(23)
Other	11	13	(2)	(15)	13	15	(2)	(13)
Total fully bundled(1)	8,348	8,751	(403)	(5)	8,751	9,556	(805)	(8)
Distribution only service	2,829	2,757	72	3	2,757	1,639	1,118	68
Total retail	11,177	11,508	(331)	(3)	11,508	11,195	313	3
Wholesale	621	741	(120)	(16)	741	656	85	13
Total GWhs sold	11,798	12,249	(451)	(4)%	12,249	11,851	398	3 %
Average number of retail customers (in thousands)	376	371	5	1 %	371	365	6	2 %
Average revenue per MWh:								
Retail - fully bundled(1)	$132.97	$106.57	$ 26.40	25 %	$106.57	$ 81.77	$ 24.80	30 %
Wholesale	$ 79.63	$ 75.48	$ 4.15	5 %	$ 75.48	$ 58.14	$ 17.34	30 %
Heating degree days	4,950	4,631	319	7 %	4,631	4,494	137	3 %
Cooling degree days	1,097	1,353	(256)	(19)%	1,353	1,366	(13)	(1)%
Sources of energy (GWhs)(2)(3):								
Natural gas	4,310	4,075	235	6 %	4,075	4,712	(637)	(14)%
Coal	759	1,077	(318)	(30)	1,077	1,220	(143)	(12)
Renewables	24	26	(2)	(8)	26	31	(5)	(16)
Total energy generated	5,093	5,178	(85)	(2)	5,178	5,963	(785)	(13)
Energy purchased	4,612	4,691	(79)	(2)	4,691	4,960	(269)	(5)
Total	9,705	9,869	(164)	(2)%	9,869	10,923	(1,054)	(10)%
Average cost of energy per MWh(2)(4):								
Energy generated	$ 64.82	$ 46.05	$ 18.77	41 %	$ 46.05	$ 28.84	$ 17.21	60 %
Energy purchased	$ 77.85	$ 67.49	$ 10.36	15 %	$ 67.49	$ 47.39	$ 20.10	42 %

(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 4, — and 2 GWhs of coal and —, — and 6 GWhs of natural gas generated energy that is purchased at cost by related parties for the years ended December 31, 2023, 2022 and 2021, 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:

	2023	2022	Change		2022	2021	Change	
Utility margin (in millions):								
Operating revenue	$ 237	$ 168	$ 69	41 %	$ 168	$ 117	$ 51	44 %
Natural gas purchased for resale	176	111	65	59	111	61	50	82
Utility margin	$ 61	$ 57	$ 4	7 %	$ 57	$ 56	$ 1	2 %
Sold (000's Dths):								
Residential	12,200	11,269	931	8 %	11,269	10,662	607	6 %
Commercial	6,276	5,897	379	6	5,897	5,524	373	7
Industrial	2,870	2,211	659	30	2,211	1,981	230	12
Total retail	21,346	19,377	1,969	10 %	19,377	18,167	1,210	7 %
Average number of retail customers (in thousands)	183	180	3	2 %	180	177	3	2 %
Average revenue per retail Dth sold	$ 11.10	$ 8.67	$ 2.43	28 %	$ 8.67	$ 6.44	$ 2.23	35 %
Heating degree days	4,950	4,631	319	7 %	4,631	4,494	137	3 %
Average cost of natural gas per retail Dth sold	$ 8.25	$ 5.73	$ 2.52	44 %	$ 5.73	$ 3.36	$ 2.37	71 %

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.

Year Ended December 31, 2022 Compared to Year Ended December 31, 2021

Electric utility margin increased $29 million, or 7%, for 2022 compared to 2021 primarily due to:

- $15 million of higher ON Line temporary rider (offset in operations and maintenance expense) for the recovery of deferred costs for ON Line due to the regulatory-directed reallocation of costs between Nevada Power and Sierra Pacific;
- $9 million of higher transmission and wholesale revenue;
- $4 million of higher regulatory-related revenue deferrals; and
- $1 million of higher electric retail utility margin due to higher customer volumes, offset by unfavorable price impacts from changes in sales mix. Retail customer volumes, including distribution only service customers, increased 2.8% primarily due to an increase in the average number of customers, offset by the unfavorable impact of weather and unfavorable changes in customer usage.

The increase in electric utility margin was offset by:

- $2 million in lower energy efficiency program rates (offset in operations and maintenance expense).

Operations and maintenance increased $26 million, or 16%, for 2022 compared to 2021 primarily due to higher regulatory-approved cost recovery for the ON Line reallocation of $15 million (offset in operating revenue) and higher plant operations and maintenance expenses, partially offset by lower energy efficiency program costs (offset in operating revenue).

Depreciation and amortization increased $6 million, or 4%, for 2022 compared to 2021 primarily due to higher plant in-service.

Interest expense increased $4 million, or 7%, for 2022 compared to 2021 primarily due to higher interest rates and debt.

Interest and dividend income increased $9 million for 2022 compared to 2021 primarily due to higher interest income, mainly from carrying charges on regulatory balances.

Other, net decreased $9 million, or 82%, for 2022 compared to 2021 primarily due to higher pension expense and lower cash surrender value of corporate-owned life insurance policies.

Liquidity and Capital Resources

As of December 31, 2023, Sierra Pacific's total net liquidity was $444 million as follows (in millions):

Cash and cash equivalents	$	44
Credit facilities[(1)]		400
Total net liquidity	$	444
Credit facilities:		
Maturity dates		2026

(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, 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.

Net cash flows from operating activities for the years ended December 31, 2022 and 2021 were $109 million and $183 million, respectively. The change was primarily due to higher payments related to fuel and energy costs and the timing of payments for operating costs, partially offset by higher collections from customers.

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, 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.

Net cash flows from investing activities for the years ended December 31, 2022 and 2021 were $(351) million and $(300) 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, 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.

Net cash flows from financing activities for the years ended December 31, 2022 and 2021 were $282 million and $107 million, respectively. The change was primarily due to higher contributions from NV Energy, Inc. and greater proceeds from the issuance of long-term debt, partially offset by higher long-term debt reacquired, higher repayments of short-term debt and higher dividends paid to NV Energy, Inc.

In February 2024, Sierra Pacific declared and paid a dividend to NV Energy, Inc. of $150 million.

Ability to Issue Debt

Sierra Pacific's ability to issue debt is primarily impacted by its financing authority from the PUCN. As of December 31, 2023, 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 $1.9 billion and to issue common and preferred stock so long as the total amounts outstanding do not exceed $2.2 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, 2023. 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.

Ability to Issue 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, 2023, $5.0 billion of Sierra Pacific's assets were pledged. Sierra Pacific had the capacity to issue $1.4 billion of additional general and refunding mortgage securities as of December 31, 2023 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.

Long-Term Debt

In February 2024, Sierra Pacific entered into a re-offering of the following series of fixed-rate tax exempt bonds: $75 million of Washoe County, Nevada Water Facilities Refunding Revenue Bonds, Series 2016F, due 2036; $60 million of Washoe County, Nevada Gas and Water Facilities Refunding Revenue Bonds, Series 2016B, due 2036; $30 million of Humboldt County, Nevada Pollution Control Refunding Revenue Bonds, Series 2016B, due 2029; $30 million of Washoe County, Nevada Water Facilities Refunding Revenue Bonds, Series 2016C, due 2036; $20 million of Humboldt County, Nevada Pollution Control Refunding Revenue Bonds, Series 2016A due 2029; and $20 million of Washoe County, Nevada Water Facilities Refunding Revenue Bonds, Series 2016G, due 2036. The Humboldt County Series 2016A and Series 2016B bonds were offered at a term rate of 3.550%. The Washoe County Series 2016B and Series 2016G bonds were offered at a fixed rate of 3.625% and the Washoe County Series 2016C and Series 2016F bonds were offered at a fixed rate of 4.125%. Sierra Pacific previously purchased the bonds as required by the bond indentures. Sierra Pacific used the net proceeds of the re-offering for general corporate purposes.

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		
	2021	2022	2023	2024	2025	2026
Electric distribution	$ 96	$ 113	$ 169	$ 207	$ 250	$ 177
Electric transmission	77	75	114	191	263	272
Solar generation	17	36	1	7	133	106
Electric battery storage	18	—	14	88	53	203
Other	92	127	90	181	204	172
Total	$ 300	$ 351	$ 388	$ 674	$ 903	$ 930

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 2024 through 2026. 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. The Nevada Utilities have received approval from the PUCN to build 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 Robinson Summit substation, near Ely, Nevada. 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, pending PUCN approval, that would be developed in Churchill County, Nevada with ownership share between Nevada Power and Sierra Pacific to be approved by the PUCN. Commercial operation of the solar 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, pending PUCN approval, that would be developed in Churchill County, Nevada with ownership share between Nevada Power and Sierra Pacific to be approved by the PUCN. Commercial operation of the battery energy storage system is expected by early 2026.
- Other includes both growth projects and operating expenditures consisting of turbine upgrades at the Tracy generating facility, a repower project at the Valmy generating station to convert existing coal-fired combustion to natural gas-fired combustion, 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 seeks, in part (1) to convert the existing coal fueled plant at North Valmy Generating Station to a cleaner natural gas fueled plant (2) to construct 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 a 149 MW photovoltaic and 149 MW battery energy storage system known as the 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 with an order expected in 2024.

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 $63 million due in 2024.

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, 2023, 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, 2023, Sierra Pacific would have been required to post $36 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 $381 million and total regulatory liabilities were $439 million as of December 31, 2023. 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, 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 2017 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, 2023, these amounts were recognized as a net regulatory liability of $206 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
As of December 31, 2023:			
Total commodity derivative contracts	$ (16)	$ (14)	$ (18)
As of December 31, 2022:			
Total commodity derivative contracts	$ (13)	$ (3)	$ (23)

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, 2023 and 2022, a net regulatory asset of $16 million and $13 million, respectively, was recorded related to the net derivative liability of $16 million and $13 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, 2023 and 2022, Sierra Pacific had no short-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. If variable interest rates were to increase by 10% from December 31 levels, it would not have a material effect on Sierra Pacific's annual interest expense. The carrying value of the variable-rate obligations approximates fair value as of December 31, 2023 and 2022.

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, 2023, 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

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, 2023 and 2022, 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, 2023, 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, 2023 and 2022, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2023, 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 audit 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 future 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 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 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 23, 2024

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, 2023	As of December 31, 2022
ASSETS		
Current assets:		
Cash and cash equivalents	$ 44	$ 49
Trade receivables, net	180	175
Inventories	117	79
Regulatory assets	161	357
Other current assets	35	50
Total current assets	537	710
Property, plant and equipment, net	3,822	3,587
Regulatory assets	220	254
Other assets	193	181
Total assets	$ 4,772	$ 4,732
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities:		
Accounts payable	$ 228	$ 224
Note payable to affiliate	—	70
Accrued interest	18	14
Accrued property, income and other taxes	21	15
Current portion of long-term debt	—	250
Customer deposits	21	18
Other current liabilities	61	61
Total current liabilities	349	652
Long-term debt	1,293	898
Finance lease obligations	94	100
Regulatory liabilities	424	436
Deferred income taxes	404	445
Other long-term liabilities	143	153
Total liabilities	2,707	2,684
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	1,576	1,576
Retained earnings	490	473
Accumulated other comprehensive loss, net	(1)	(1)
Total shareholder's equity	2,065	2,048
Total liabilities and shareholder's equity	$ 4,772	$ 4,732

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,		
	2023	2022	2021
Operating revenue:			
Regulated electric	$ 1,194	$ 1,025	$ 848
Regulated natural gas	237	168	117
Total operating revenue	1,431	1,193	965
Operating expenses:			
Cost of fuel and energy	689	555	407
Cost of natural gas purchased for resale	176	111	61
Operations and maintenance	204	189	163
Depreciation and amortization	185	149	143
Property and other taxes	25	24	24
Total operating expenses	1,279	1,028	798
Operating income	152	165	167
Other income (expense):			
Interest expense	(66)	(58)	(54)
Allowance for borrowed funds	7	3	2
Allowance for equity funds	14	7	7
Interest and dividend income	22	18	9
Other, net	4	2	11
Total other income (expense)	(19)	(28)	(25)
Income before income tax expense	133	137	142
Income tax expense	16	19	18
Net income	$ 117	$ 118	$ 124

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 Paid-in Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Loss, Net	Total Shareholder's Equity
	Shares	Amount				
Balance, December 31, 2020	1,000	$ —	$ 1,111	$ 301	$ (1)	$ 1,411
Net income	—	—	—	124	—	124
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

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,		
	2023	**2022**	**2021**
Cash flows from operating activities:			
Net income	$ 117	$ 118	$ 124
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	185	149	143
Allowance for equity funds	(14)	(7)	(7)
Deferred energy	117	(267)	(116)
Amortization of deferred energy	83	97	29
Other changes in regulatory assets and liabilities	1	(1)	(39)
Deferred income taxes and amortization of investment tax credits	(56)	31	13
Other, net	—	3	(1)
Changes in other operating assets and liabilities:			
Trade receivables and other assets	(7)	(52)	(27)
Inventories	(38)	(14)	12
Accrued property, income and other taxes	18	(13)	9
Accounts payable and other liabilities	13	65	43
Net cash flows from operating activities	419	109	183
Cash flows from investing activities:			
Capital expenditures	(388)	(351)	(300)
Net cash flows from investing activities	(388)	(351)	(300)
Cash flows from financing activities:			
Proceeds from long-term debt	393	248	—
Long-term debt reacquired	—	(265)	—
Repayments of long-term debt	(250)	—	—
Net (repayments of) proceeds from short-term debt	—	(159)	114
Net (repayments of) proceeds from affiliate note payable	(70)	70	—
Dividends paid	(100)	(70)	—
Contributions from parent	—	465	—
Other, net	(8)	(7)	(7)
Net cash flows from financing activities	(35)	282	107
Net change in cash and cash equivalents and restricted cash and cash equivalents	(4)	40	(10)
Cash and cash equivalents and restricted cash and cash equivalents at beginning of period	56	16	26
Cash and cash equivalents and restricted cash and cash equivalents at end of period	$ 52	$ 56	$ 16

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 owns subsidiaries principally engaged in energy businesses. BHE is a consolidated 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, 2023, 2022 and 2021.

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 PUCN for a certain renewable energy contract. A reconciliation of cash and cash equivalents and restricted cash and cash equivalents as of December 31, 2023 and December 31, 2022, 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,	
	2023	2022
Cash and cash equivalents	$ 44	$ 49
Restricted cash and cash equivalents included in other current assets	8	7
Total cash and cash equivalents and restricted cash and cash equivalents	$ 52	$ 56

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):

	2023	2022	2021
Beginning balance	$ 2	$ 1	$ 2
Charged to operating costs and expenses, net	4	2	2
Write-offs, net	(3)	(1)	(3)
Ending balance	$ 3	$ 2	$ 1

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 $95 million and $69 million as of December 31, 2023 and 2022, respectively, and fuel, which includes coal stock, stored natural gas and fuel oil, totaling $22 million and $10 million as of December 31, 2023 and 2022, 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 Public Utilities Commission of Nevada ("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 asset or liability.

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 2023 and 2022 was 6.85% and 5.52%, respectively, for electric, 5.75% and 5.09%, respectively, for natural gas and 6.76% and 5.23%, 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, 2023 and 2022, trade receivables, net on the Consolidated Balance Sheets relate substantially to Customer Revenue, including unbilled revenue of $95 million and $94 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 on the Consolidated Statements of Operations.

New Accounting Pronouncements

In November 2023, the FASB issued 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 is currently evaluating the impact of adopting this guidance on its 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. 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	2023	2022
Utility plant:			
Electric generation	25 - 70 years	$ 1,313	$ 1,298
Electric transmission	50 - 76 years	1,023	993
Electric distribution	20 - 76 years	2,074	1,983
Electric general and intangible plant	5 - 65 years	247	219
Natural gas distribution	35 - 70 years	537	455
Natural gas general and intangible plant	5 - 65 years	17	15
Common general	5 - 65 years	376	380
Utility plant		5,587	5,343
Accumulated depreciation and amortization		(2,091)	(1,992)
Utility plant, net		3,496	3,351
Construction work-in-progress		326	236
Property, plant and equipment, net		$ 3,822	$ 3,587

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, 2023, 2022 and 2021 was 3.3%, 3.0% and 3.1%, 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.

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, 2023 (dollars in millions):

	Sierra Pacific's Share	Utility Plant	Accumulated Depreciation	Construction Work-in-Progress
Valmy Generating Station	50 %	$ 405	$ 351	$ 4
ON Line Transmission Line	6	43	14	—
Valmy Transmission	50	4	2	5
Total		$ 452	$ 367	$ 9

(5) Leases

The following table summarizes Sierra Pacific's leases recorded on the Consolidated Balance Sheet as of December 31 (in millions):

	2023	2022
Right-of-use assets:		
Operating leases	$ 16	$ 16
Finance leases	100	105
Total right-of-use assets	$ 116	$ 121
Lease liabilities:		
Operating leases	$ 15	$ 15
Finance leases	103	108
Total lease liabilities	$ 118	$ 123

The following table summarizes Sierra Pacific's lease costs for the years ended December 31 (in millions):

	2023	2022	2021
Variable	$ 99	$ 103	$ 86
Operating	2	1	1
Finance:			
Amortization	5	5	5
Interest	8	8	9
Total lease costs	$ 114	$ 117	$ 101
Weighted-average remaining lease term (years):			
Operating leases	24.6	26.0	27.4
Finance leases	27.6	28.2	28.4
Weighted-average discount rate:			
Operating leases	5.0 %	5.0 %	5.0 %
Finance leases	8.4 %	8.4 %	8.2 %

The following table summarizes Sierra Pacific's supplemental cash flow information relating to leases for the years ended December 31 (in millions):

	2023	2022	2021
Cash paid for amounts included in the measurement of lease liabilities:			
Operating cash flows from operating leases	$ (2)	$ (1)	$ (1)
Operating cash flows from finance leases	(8)	(9)	(9)
Financing cash flows from finance leases	(7)	(7)	(7)
Right-of-use assets obtained in exchange for lease liabilities:			
Operating leases	$ 1	$ 1	$ —
Finance leases	3	1	1

Sierra Pacific has the following remaining lease commitments as of December 31, 2023 (in millions):

	Operating	Finance	Total
2024	$ 1	$ 16	$ 17
2025	1	16	17
2026	1	15	16
2027	1	13	14
2028	1	12	13
Thereafter	23	127	150
Total undiscounted lease payments	28	199	227
Less - amounts representing interest	(13)	(96)	(109)
Lease liabilities	$ 15	$ 103	$ 118

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 $117 million and $107 million were included on the Consolidated Balance Sheets as of December 31, 2023 and 2022, 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	2023	2022
Natural disaster protection plan	1 year	$ 78	$ 69
Deferred energy costs	1 year	77	277
Merger costs from 1999 merger	23 years	60	63
Employee benefit plans (1)	8 years	48	57
Deferred operating costs	4 years	25	35
Other	Various	93	110
Total regulatory assets		$ 381	$ 611
Reflected as:			
Current assets		$ 161	$ 357
Noncurrent assets		220	254
Total regulatory assets		$ 381	$ 611

(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 $132 million and $143 million as of December 31, 2023 and 2022, 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	2023	2022
Deferred income taxes[1]	Various	$ 206	$ 223
Cost of removal[2]	31 years	211	200
Other	Various	22	32
Total regulatory liabilities		$ 439	$ 455
Reflected as:			
Current liabilities		$ 15	$ 19
Noncurrent liabilities		424	436
Total regulatory liabilities		$ 439	$ 455

(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 prudency 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 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 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. Orders are expected by the third quarter of 2024 and, if approved, would be effective October 1, 2024.

(7) Short-term Debt and Credit Facilities

Sierra Pacific has a $400 million secured credit facility expiring in June 2026 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, 2023 and 2022, 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, 2023, Sierra Pacific had $50 million of letter of credit capacity under its $400 million secured credit facility, of which no amount was outstanding.

As of December 31, 2022, Sierra Pacific had $75 million of letter of credit capacity under its $250 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	2023	2022
General and refunding mortgage securities:			
3.375% Series T, due 2023	$ —	$ —	$ 249
2.600% Series U, due 2026	400	398	397
6.750% Series P, due 2037	252	254	254
4.710% Series W, due 2052	250	248	248
5.900% Series 2023A, due 2054	400	393	—
Total long-term debt	$ 1,302	$ 1,293	$ 1,148
Reflected as:			
Current portion of long-term debt		$ —	$ 250
Long-term debt		1,293	898
Total long-term debt		$ 1,293	$ 1,148

Annual Payment on Long-Term Debt

The annual repayments of long-term debt for the years beginning January 1, 2024 and thereafter, are as follows (in millions):

2026	$ 400
2029 and thereafter	902
Total	1,302
Unamortized premium, discount and debt issuance cost	(9)
Total	$ 1,293

In February 2024, Sierra Pacific entered into a re-offering of the following series of fixed-rate tax exempt bonds: $75 million of Washoe County, Nevada Water Facilities Refunding Revenue Bonds, Series 2016F, due 2036; $60 million of Washoe County, Nevada Gas and Water Facilities Refunding Revenue Bonds, Series 2016B, due 2036; $30 million of Humboldt County, Nevada Pollution Control Refunding Revenue Bonds, Series 2016B, due 2029; $30 million of Washoe County, Nevada Water Facilities Refunding Revenue Bonds, Series 2016C, due 2036; $20 million of Humboldt County, Nevada Pollution Control Refunding Revenue Bonds, Series 2016A due 2029; and $20 million of Washoe County, Nevada Water Facilities Refunding Revenue Bonds, Series 2016G, due 2036. The Humboldt County Series 2016A and Series 2016B bonds were offered at a term rate of 3.550%. The Washoe County Series 2016B and Series 2016G bonds were offered at a fixed rate of 3.625% and the Washoe County Series 2016C and Series 2016F bonds were offered at a fixed rate of 4.125%. Sierra Pacific previously purchased the bonds as required by the bond indentures. Sierra Pacific used the net proceeds of the re-offering for general corporate purposes.

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, 2023, approximately $5.0 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):

	2023	2022	2021
Current – Federal	$ 72	$ (12)	$ 5
Deferred – Federal	(57)	31	13
Investment tax credits	1	—	—
Total income tax expense	$ 16	$ 19	$ 18

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:

	2023	2022	2021
Federal statutory income tax rate	21 %	21 %	21 %
Effects of ratemaking	(9)	(7)	(8)
Effective income tax rate	12 %	14 %	13 %

The net deferred income tax liability consists of the following as of December 31 (in millions):

	2023	2022
Deferred income tax assets:		
Regulatory liabilities	$ 62	$ 63
Operating and finance leases	25	26
Customer advances	16	17
Unamortized contract value	3	6
Other	5	6
Total deferred income tax assets	111	118
Deferred income tax liabilities:		
Property-related items	(376)	(387)
Regulatory assets	(100)	(135)
Operating and finance leases	(24)	(25)
Other	(15)	(16)
Total deferred income tax liabilities	(515)	(563)
Net deferred income tax liability	$ (404)	$ (445)

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, 2023, 2022 and 2021. Sierra Pacific contributed $1 million to the Non-Qualified Pension Plans for the years ended December 31, 2023, 2022 and 2021. Sierra Pacific contributed $3 million, $5 million, and $1 million to the Other Post Retirement Plans for the years ended December 31, 2023, 2022, and 2021 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):

	2023	2022
Qualified Pension Plan -		
Other non-current assets	$ 53	$ 43
Non-Qualified Pension Plans:		
Other current liabilities	(1)	(1)
Other long-term liabilities	(5)	(5)
Other Postretirement Plans:		
Other non-current assets	1	—
Other long-term liabilities	—	(2)

(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 $211 million and $200 million as of December 31, 2023 and 2022, respectively.

The following table presents Sierra Pacific's ARO liabilities by asset type as of December 31 (in millions):

	2023	2022
Asbestos	$ 5	$ 5
Evaporative ponds and dry ash landfills	3	3
Solar-powered generating facilities	1	—
Other	3	3
Total asset retirement obligations	$ 12	$ 11

The following table reconciles the beginning and ending balances of Sierra Pacific's ARO liabilities for the years ended December 31 (in millions):

	2023	2022
Beginning balance	$ 11	$ 11
Additions	1	—
Ending balance	$ 12	$ 11
Reflected as -		
Other long-term liabilities	$ 12	$ 11

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.

(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 Current Assets	Other Current Liabilities	Other Long-term Liabilities	Total
As of December 31, 2023:				
Not designated as hedging contracts [1] -				
Commodity liabilities	$ —	$ (16)	$ —	$ (16)
As of December 31, 2022:				
Not designated as hedging contracts[1]:				
Commodity assets	$ 8	$ —	$ —	$ 8
Commodity liabilities	—	(14)	(7)	(21)
Total derivative - net basis	$ 8	$ (14)	$ (7)	$ (13)

(1) Sierra Pacific's commodity derivatives not designated as hedging contracts are included in regulated rates. As of December 31, 2023 and 2022, a regulatory asset of $16 million and $13 million, respectively, was recorded related to the net derivative liability of $16 million and $13 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	2023	2022
Electricity purchases	Megawatt hours	—	1
Natural gas purchases	Decatherms	55	52

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.

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 Sierra Pacific's creditworthiness. These rights can vary by contract and by counterparty. As of December 31, 2023, 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 $1 million and $— million as of December 31, 2023 and 2022, 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, 2023:				
Assets:				
Money market mutual funds	$ 41	$ —	$ —	$ 41
Investment funds	1	—	—	1
	$ 42	$ —	$ —	$ 42
Liabilities - commodity derivatives	$ —	$ —	$ (16)	$ (16)
As of December 31, 2022:				
Assets:				
Commodity derivatives	$ —	$ —	$ 8	$ 8
Money market mutual funds	49	—	—	49
Investment funds	1	—	—	1
	$ 50	$ —	$ 8	$ 58
Liabilities - commodity derivatives	$ —	$ —	$ (21)	$ (21)

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, 2023, 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):

	2023	2022	2021
Beginning balance	$ (13)	$ (33)	$ 7
Changes in fair value recognized in regulatory assets or liabilities	(50)	(21)	(25)
Settlements	47	41	(15)
Ending balance	$ (16)	$ (13)	$ (33)

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):

	2023		2022	
	Carrying Value	**Fair Value**	**Carrying Value**	**Fair Value**
Long-term debt	$ 1,293	$ 1,311	$ 1,148	$ 1,111

(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, 2023 are as follows (in millions):

	2024	2025	2026	2027	2028	2029 and Thereafter	Total
Contract type:							
Purchased electricity contracts - commercially operable	$ 124	$ 119	$ 120	$ 112	$ 106	$ 1,471	$ 2,052
Purchased electricity contracts - non-commercially operable	—	9	25	41	54	1,576	1,705
Fuel contracts	90	43	26	26	26	81	292
Construction commitments	40	154	305	31	1	—	531
Transmission	32	12	—	—	—	—	44
Easements	2	2	2	2	2	31	41
Maintenance, service and other contracts	7	15	15	1	1	3	42
Total commitments	$ 295	$ 354	$ 493	$ 213	$ 190	$ 3,162	$ 4,707

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 2024. Additionally, gas transportation contracts expire from 2024 to 2046.

Construction Commitments

Sierra Pacific's construction commitments included in the table above relate to firm commitments and include costs associated with a solar photovoltaic facility project, solar photovoltaic panels for future projects, the planned Greenlink Nevada transmission expansion project that will be developed in western and northern Nevada and other certain plant projects. The solar project, pending PUCN approval, is a 400-MW solar photovoltaic facility with an additional 400 MWs of co-located battery storage that would be developed in Churchill County, Nevada.

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, 2023, 2022 and 2021.

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 2024 to 2046.

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. Plaintiffs occasionally seek punitive or exemplary damages. Sierra Pacific does not believe that such normal and routine litigation will have a material impact on its financial results. Sierra Pacific is also involved in other kinds of legal actions, some of which assert or may assert claims or seek to impose fines, penalties and other costs in substantial amounts.

(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):

	2023			2022			2021		
	Electric	**Natural Gas**	**Total**	**Electric**	**Natural Gas**	**Total**	**Electric**	**Natural Gas**	**Total**
Customer Revenue:									
Retail:									
Residential	$ 421	$ 143	$ 564	$ 365	$ 105	$ 470	$ 307	$ 76	$ 383
Commercial	385	64	449	333	45	378	267	29	296
Industrial	299	27	326	229	16	245	202	10	212
Other	5	1	6	6	1	7	5	—	5
Total fully bundled	1,110	235	1,345	933	167	1,100	781	115	896
Distribution only service	5	—	5	5	—	5	3	—	3
Total retail	1,115	235	1,350	938	167	1,105	784	115	899
Wholesale, transmission and other	78	—	78	86	—	86	62	—	62
Total Customer Revenue	1,193	235	1,428	1,024	167	1,191	846	115	961
Other revenue	1	2	3	1	1	2	2	2	4
Total operating revenue	$ 1,194	$ 237	$ 1,431	$ 1,025	$ 168	$ 1,193	$ 848	$ 117	$ 965

(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):

	2023	2022	2021
Supplemental disclosure of cash flow information:			
Interest paid, net of amounts capitalized	$ 49	$ 45	$ 41
Income taxes paid (refunded)	$ 56	$ (1)	$ (3)
Supplemental disclosure of non-cash investing and financing transactions:			
Accruals related to property, plant and equipment additions	$ 51	$ 57	$ 27

(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 $27 million, $23 million and $14 million for the years ended December 31, 2023, 2022 and 2021. Amounts charged to Sierra Pacific in 2023 and 2022 primarily relate to information technology projects billed at a consolidated level and passed through to affiliates.

Sierra Pacific provided electricity to Nevada Power of $70 million, $86 million and $43 million for the years ended December 31, 2023, 2022 and 2021, respectively. Receivables associated with these transactions were $1 million and $5 million as of December 31, 2023 and 2022, respectively. Sierra Pacific purchased electricity from Nevada Power of $230 million, $362 million and $179 million for the years ended December 31, 2023, 2022 and 2021, respectively. Payables associated with these transactions were $10 million and $41 million as of December 31, 2023 and 2022, 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, 2023, 2022 and 2021, respectively. Sierra Pacific provided services to Nevada Power of $19 million, $16 million, and $15 million for the years ended December 31, 2023, 2022 and 2021, respectively. Nevada Power provided services to Sierra Pacific of $28 million, $25 million, and $25 million for the years ended December 31, 2023, 2022 and 2021, respectively. Sierra Pacific provided services to NV Energy of $1 million, $1 million, and $— million for the years ended December 31, 2023, 2022 and 2021, respectively. As of December 31, 2023 and 2022, Sierra Pacific's Consolidated Balance Sheets included amounts due to NV Energy of $24 million and $47 million, respectively. There were no receivables due from NV Energy as of December 31, 2023 and 2022. In November 2022, Sierra Pacific entered into a $100 million unsecured note with NV Energy payable upon demand and $— million and $70 million was outstanding as of December 31, 2023 and 2022, respectively. As of December 31, 2023 and 2022, Sierra Pacific's Consolidated Balance Sheets included payables due to Nevada Power of $— million and $33 million, respectively. There were $20 million and $— million receivables due from Nevada Power as of December 31, 2023 and 2022.

Sierra Pacific is party to a tax-sharing agreement with NV Energy and NV Energy is part of the Berkshire Hathaway consolidated U.S. federal income tax return. Federal income taxes payable to NV Energy were $4 million as of December 31, 2023 and federal income taxes receivable from NV Energy were $11 million as of December 31, 2022. Sierra Pacific made cash payments of $55 million for federal income taxes for the year ended December 31, 2023 and received cash refunds of $1 million and $3 million for federal income taxes for the years ended December 31, 2022 and 2021, respectively.

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 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):

	Years Ended December 31,		
	2023	2022	2021
Operating revenue:			
Regulated electric	$ 1,194	$ 1,025	$ 848
Regulated natural gas	237	168	117
Total operating revenue	$ 1,431	$ 1,193	$ 965
Operating income:			
Regulated electric	$ 133	$ 146	$ 148
Regulated natural gas	19	19	19
Total operating income	152	165	167
Interest expense	(66)	(58)	(54)
Allowance for borrowed funds	7	3	2
Allowance for equity funds	14	7	7
Interest and dividend income	22	18	9
Other, net	4	2	11
Income before income tax expense	$ 133	$ 137	$ 142

	As of December 31,		
	2023	2022	2021
Assets			
Regulated electric	$ 4,251	$ 4,224	$ 3,829
Regulated natural gas	454	441	365
Regulated common assets(1)	67	67	29
Total assets	$ 4,772	$ 4,732	$ 4,223

(1) 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, 2023 was $474 million, an increase of $48 million, or 11%, compared to 2022, primarily due to the acquisition of DEI's 50% noncontrolling 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.

Net income attributable to Eastern Energy Gas for the year ended December 31, 2022 was $426 million, an increase of $164 million, or 63%, compared to 2021, primarily due to higher margin from EGTS' regulated gas transmission and storage operations of $128 million, a benefit from the settlement of regulated tax matters in the Iroquois rate case and a decrease due to the settlement of depreciation rates in EGTS' general rate case, partially offset by an increase in income tax expense primarily due to higher pre-tax income.

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 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 DEI's 50% noncontrolling 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 DEI's 50% noncontrolling interest in Cove Point of $63 million and lower net income attributable to Cove Point of $4 million.

Year Ended December 31, 2022 Compared to Year Ended December 31, 2021

Operating revenue increased $136 million, or 7%, for 2022 compared to 2021, primarily due to an increase in regulated gas transmission and storage services revenues due to the settlement of EGTS' general rate case of $101 million, an increase in Cove Point LNG variable revenue of $69 million and an increase in variable revenue related to park and loan activity of $24 million, partially offset by a decrease in regulated gas sales for operational and system balancing purposes primarily due to decreased volumes of $49 million and decreased LNG service as a result of increased scheduled maintenance days of $13 million.

Cost of (excess) gas was a credit of $30 million for 2022 compared to an expense of $12 million for 2021. The change is primarily due to a decrease in volumes sold of $62 million, partially offset by an unfavorable change to operational and system balancing volumes of $20 million.

Operations and maintenance increased $15 million, or 3%, for 2022 compared to 2021, primarily due to a 2021 benefit from the finalization of entries for the disallowance of capitalized AFUDC of $11 million and higher technology and related charges of $11 million, partially offset by lower long-term incentive plan expenses of $8 million.

Depreciation and amortization decreased $7 million, or 2%, for 2022 compared to 2021, primarily due to the settlement of depreciation rates in EGTS' general rate case of $23 million, partially offset by higher plant placed in-service of $16 million.

Property and other taxes decreased $10 million, or 7%, for 2022 compared to 2021, primarily due to lower than estimated 2021 tax assessments.

Interest expense decreased $4 million, or 3%, for 2022 compared to 2021, primarily due to the repayment of $500 million of long-term debt in the second quarter of 2021.

Interest and dividend income increased $7 million for 2022 compared to 2021, primarily due to interest income from BHE GT&S' intercompany revolving credit agreement with Eastern Energy Gas.

Other, net was an expense of $1 million for 2022 compared to a credit of $1 million for 2021. The change is primarily due to losses on marketable securities.

Income tax expense increased $50 million, or 43%, for 2022 compared to 2021 and the effective tax rate was 18% for 2022 and 16% for 2021. The effective tax rate increased primarily due to the revaluation of deferred taxes from changes in various state income tax rates.

Equity income increased $59 million for 2022 compared to 2021, primarily due to a benefit from the settlement of regulated tax matters in the Iroquois rate case of $45 million and higher operating revenues at Iroquois due to favorable fixed negotiated rate agreements and hedges of $15 million.

Net income attributable to noncontrolling interests increased $33 million for 2022 compared to 2021, primarily due to an increase in Cove Point LNG variable revenue, partially offset by decreased LNG service as a result of increased scheduled maintenance days.

Liquidity and Capital Resources

As of December 31, 2023, Eastern Energy Gas' total net liquidity was as follows (in millions):

Cash and cash equivalents	$	62
Intercompany revolving credit agreement[1]		400
Less:		
Notes payable to affiliates		400
Net intercompany revolving credit agreement		—
Total net liquidity	$	62
Intercompany revolving credit agreement:		
Maturity date		2025

(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, 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.

Net cash flows from operating activities for the years ended December 31, 2022 and 2021 were $1.3 billion and $1.1 billion, respectively. The change was primarily due to the impacts from the proposed rate increase in effect April 1, 2022 for the EGTS general rate case, timing of income tax payments and other changes in working capital, partially offset by lower collections from customers.

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

Investing Activities

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 affiliates of $695 million, a decrease in notes 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.

Net cash flows from investing activities for the years ended December 31, 2022 and 2021 were $(778) million and $(486) million, respectively. The change was primarily due to an increase in notes to its parent under an intercompany revolving credit agreement of $381 million and lower repayments of notes by affiliates of $266 million, partially offset by equity method distribution of $150 million in 2022, equity method contributions of $154 million in 2021 and a decrease in capital expenditures of $55 million.

Financing Activities

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.

Net cash flows from financing activities for the year ended December 31, 2021 were $(615) million. Sources of cash totaled $346 million and consisted of proceeds from equity contributions, that included a contribution from its indirect parent, BHE, to Eastern Energy Gas to assist in the repayment of $500 million of debt. Uses of cash totaled $961 million and consisted mainly of repayments of long-term debt of $500 million, distributions to noncontrolling interests from Cove Point of $450 million and repayment of notes to affiliates of $9 million.

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, 2022. For further discussion, refer to Note 19 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Long-term Debt

Eastern Energy Gas currently has an effective shelf registration statement with the SEC to issue up to $2.5 billion 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		
	2021	**2022**	**2023**	**2024**	**2025**	**2026**
Natural gas transmission and storage	$ 16	$ 43	$ 23	$ 54	$ 86	$ 90
Other	426	344	342	347	343	340
Total	$ 442	$ 387	$ 365	$ 401	$ 429	$ 430

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, 2023, Eastern Energy Gas' investments that are accounted for under the equity method had short- and long-term debt of $303 million and an unused revolving credit facility of $10 million. As of December 31, 2023, Eastern Energy Gas' pro-rata share of such short- and long-term debt was $152 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, 2023 (in millions):

	Payments Due by Periods				
	2024	2025-2026	2027-2028	2029 and thereafter	Total
Interest payments on long-term debt[1]	$ 118	$ 174	$ 155	$ 934	$ 1,381
Natural gas supply and transmission[1]	46	92	93	26	257
Total cash requirements	$ 164	$ 266	$ 248	$ 960	$ 1,638

(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 $54 million and total regulatory liabilities were $656 million as of December 31, 2023. 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, 2023 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, 2023. Additionally, no indicators of impairment were identified as of December 31, 2023. 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. 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 2017 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, 2023, these amounts were recognized as a net regulatory liability of $425 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 commodity prices, 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.

Commodity Price Risk

As of February 2023, all of Eastern Energy Gas' regulated operations recover their cost of gas through fuel trackers and are no longer subject to significant commodity price risk.

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, 2023, Eastern Energy Gas had short-term variable-rate obligations totaling $400 million 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, 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, 2023 and 2022, 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, 2023 and 2022.

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, 2023, Eastern Energy Gas' credit exposure totaled $24 million. Of this amount, investment grade counterparties, including those internally rated, represented 100%, and no single counterparty, whether investment grade or non-investment grade, exceeded $5 million of exposure.

Item 8. Financial Statements and Supplementary Data

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, 2023 and 2022, 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, 2023, 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, 2023 and 2022, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2023, 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 audit 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 audit 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 ("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 future 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 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 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 23, 2024

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,	
	2023	2022
ASSETS		
Current assets:		
Cash and cash equivalents	$ 62	$ 65
Restricted cash and cash equivalents	31	30
Trade receivables, net	195	202
Receivables from affiliates	25	30
Notes receivable from affiliates	—	536
Inventories	142	127
Income taxes receivable	80	17
Prepayments and other deferred charges	76	78
Natural gas imbalances	39	193
Other current assets	20	25
Total current assets	670	1,303
Property, plant and equipment, net	10,343	10,202
Goodwill	1,286	1,286
Investments	281	278
Other assets	120	95
Total assets	$ 12,700	$ 13,164

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,	
	2023	**2022**
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 89	$ 86
Accounts payable to affiliates	45	10
Accrued property, income and other taxes	93	77
Notes payable to affiliates	400	—
Regulatory liabilities	33	126
Current portion of long-term debt	1,050	649
Other current liabilities	108	165
Total current liabilities	1,818	1,113
Long-term debt	2,204	3,243
Regulatory liabilities	623	596
Deferred income taxes	383	166
Other long-term liabilities	144	158
Total liabilities	5,172	5,276
Commitments and contingencies (Note 14)		
Equity:		
Member's equity:		
Membership interests	6,273	3,983
Accumulated other comprehensive loss, net	(40)	(42)
Total member's equity	6,233	3,941
Noncontrolling interests	1,295	3,947
Total equity	7,528	7,888
Total liabilities and equity	$ 12,700	$ 13,164

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,		
	2023	**2022**	**2021**
Operating revenue	$ 2,059	$ 2,006	$ 1,870
Operating expenses:			
Cost of (excess) gas	38	(30)	12
Operations and maintenance	590	530	515
Depreciation and amortization	322	321	328
Property and other taxes	134	139	149
Total operating expenses	1,084	960	1,004
Operating income	975	1,046	866
Other income (expense):			
Interest expense	(146)	(147)	(151)
Allowance for borrowed funds	2	2	2
Allowance for equity funds	8	6	7
Interest and dividend income	30	7	—
Other, net	(3)	(1)	1
Total other income (expense)	(109)	(133)	(141)
Income before income tax expense (benefit) and equity income (loss)	866	913	725
Income tax expense (benefit)	110	167	117
Equity income (loss)	74	103	44
Net income	830	849	652
Net income attributable to noncontrolling interests	356	423	390
Net income attributable to Eastern Energy Gas	$ 474	$ 426	$ 262

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,		
	2023	2022	2021
Net income	$ 830	$ 849	$ 652
Other comprehensive income, net of tax:			
Unrecognized amounts on retirement benefits, net of tax of $(1), $— and $—	(2)	5	6
Unrealized gains (losses) on cash flow hedges, net of tax of $3, $— and $1	5	(1)	9
Total other comprehensive income, net of tax	3	4	15
Comprehensive income	833	853	667
Comprehensive income attributable to noncontrolling interests	356	426	395
Comprehensive income attributable to Eastern Energy Gas	$ 477	$ 427	$ 272

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, 2020	$ 2,957	$ (53)	$ 4,091	$ 6,995
Net income	262	—	390	652
Other comprehensive income	—	10	5	15
Distributions	(137)	—	(450)	(587)
Contributions	419	—	—	419
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

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,		
	2023	2022	2021
Cash flows from operating activities:			
Net income	$ 830	$ 849	$ 652
Adjustments to reconcile net income to net cash flows from operating activities:			
(Gains) losses on other items, net	(3)	5	(3)
Depreciation and amortization	322	321	328
Allowance for equity funds	(8)	(6)	(7)
Equity income, net of distributions	(1)	(58)	—
Changes in regulatory assets and liabilities	(91)	56	(20)
Deferred income taxes	353	126	186
Other, net	(5)	8	(19)
Changes in other operating assets and liabilities:			
Trade receivables and other assets	29	(48)	(66)
Gas balancing activities	22	(29)	73
Derivative collateral, net	1	(1)	10
Accrued property, income and other taxes	(232)	27	(30)
Accounts payable and other liabilities	(19)	99	(12)
Net cash flows from operating activities	1,198	1,349	1,092
Cash flows from investing activities:			
Capital expenditures	(365)	(387)	(442)
Proceeds from assignment of shale development rights	8	—	—
Notes to affiliates	(198)	(564)	(183)
Repayment of notes by affiliates	734	39	305
Equity method investments	—	150	(154)
Other, net	(2)	(16)	(12)
Net cash flows from investing activities	177	(778)	(486)
Cash flows from financing activities:			
Repayments of long-term debt	(650)	—	(500)
Repayment of affiliated current borrowings, net	—	—	(9)
Issuance of notes payable to affiliates, net	400	—	—
Proceeds from equity contributions	2,893	—	346
Purchase of Cove Point noncontrolling interest	(3,300)	—	—
Distributions to noncontrolling interests	(388)	(515)	(450)
Distributions to parent	(332)	—	—
Other, net	—	—	(2)
Net cash flows from financing activities	(1,377)	(515)	(615)
Net change in cash and cash equivalents and restricted cash and cash equivalents	(2)	56	(9)
Cash and cash equivalents and restricted cash and cash equivalents at beginning of period	95	39	48
Cash and cash equivalents and restricted cash and cash equivalents at end of period	$ 93	$ 95	$ 39

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. On September 1, 2023, Eastern Energy Gas completed its acquisition of 50% of the limited partner interests in Cove Point from Dominion Energy, Inc. ("DEI"), and accordingly, owns an aggregate of 75% of the limited partner interest and continues to own 100% of the general partner interest of Cove Point. See Note 3 for more information. In addition, Eastern Energy Gas owns a 50% noncontrolling interest in Iroquois Gas Transmission System, L.P. ("Iroquois"), a 416-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 owns subsidiaries principally engaged in the energy industry. BHE is a consolidated 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, 2023 and 2022, 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,	
	2023	2022
Cash and cash equivalents	$ 62	$ 65
Restricted cash and cash equivalents	31	30
Total cash and cash equivalents and restricted cash and cash equivalents	$ 93	$ 95

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 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 evaluates the financial condition of the individual customer and the nature of any disputed amount.

The changes in the balance of the allowance for credit losses, which is included in trades receivables, net on the Consolidated Balance Sheets, is summarized as follows for the years ended December 31, (in millions):

	2023	2022	2021
Beginning balance	$ 3	$ 6	$ 5
Charged to operating costs and expenses, net	—	—	1
Write-offs, net	—	(3)	—
Ending balance	$ 3	$ 3	$ 6

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 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 natural gas pipeline 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. 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, 2023. 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 2023, 2022 and 2021, 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.

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, 2023 and 2022, trade receivables, net on the Consolidated Balance Sheets relate substantially to Customer Revenue, including unbilled revenue of $26 million and $18 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 $8 million and $10 million as of December 31, 2023 and 2022, respectively, and $40 million and $80 million of contract liabilities as of December 31, 2023 and 2022, respectively, 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 year ended December 31, 2023, Eastern Energy Gas recognized revenue of $52 million from the beginning contract liability balance.

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 segment, which includes its natural gas pipeline, storage and LNG operations.

New Accounting Pronouncements

In November 2023, the FASB issued 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 is currently evaluating the impact of adopting this guidance on its 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.

(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 (the "Seller"), an indirect wholly owned subsidiary of DEI, 50% limited partner interests in 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. 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 owns an aggregate of 75% of the limited partner interests, and its affiliate, Cove Point GP Holding Company, LLC, continues to own 100% of the general partner interest, of Cove Point. Prior to the Transaction, Eastern Energy Gas owned 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' ownership 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	2023	2022
Utility Plant:			
Interstate natural gas transmission and storage assets	23 - 49 years	$ 9,318	$ 8,922
Intangible plant	5 - 18 years	117	113
Utility plant in-service		9,435	9,035
Accumulated depreciation and amortization		(3,201)	(3,039)
Utility plant in-service, net		6,234	5,996
Nonutility Plant:			
LNG facility	40 years	4,533	4,547
Accumulated depreciation and amortization		(655)	(542)
Nonutility plant, net		3,878	4,005
		10,112	10,001
Construction work- in-progress		231	201
Property, plant and equipment, net		$ 10,343	$ 10,202

Construction work-in-progress includes $223 million and $181 million as of December 31, 2023 and 2022, 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, 2023 (dollars in millions):

	Eastern Energy Gas' Share	Facility in Service	Accumulated Depreciation and Amortization	Construction Work-in-Progress
Ellisburg Pool	39 %	$ 33	$ 12	$ —
Ellisburg Station	50	29	9	2
Harrison	50	56	19	1
Leidy	50	148	49	2
Oakford	50	216	73	4
Total		$ 482	$ 162	$ 9

(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	2023	2022
Employee benefit plans[1]	11 years	$ 33	$ 32
Other	Various	21	16
Total regulatory assets		$ 54	$ 48
Reflected as:			
Other current assets		$ 9	$ 8
Other assets		45	40
Total regulatory assets		$ 54	$ 48

(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 $48 million and $44 million as of December 31, 2023 and 2022, 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	2023	2022
Income taxes refundable through future rates[1]	Various	$ 425	$ 406
Other postretirement benefit costs[2]	Various	124	123
Provision for rate refunds[3]		—	90
Cost of removal[4]	47 years	85	82
Other	Various	22	21
Total regulatory liabilities		$ 656	$ 722
Reflected as:			
Current liabilities		$ 33	$ 126
Noncurrent liabilities		623	596
Total regulatory liabilities		$ 656	$ 722

(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) Reflects amounts refunded to customers in late February 2023 in connection with the EGTS rate case. See below for more information.

(4) 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 transportation rates by 84% and Zone 2 general system transportation 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 and the outcome of hearing procedures. This matter is pending.

Eastern Gas Transmission and Storage, Inc.

In September 2021, EGTS filed a general rate case for its FERC-jurisdictional services, with proposed rates to be effective November 1, 2021. EGTS proposed an annual cost-of-service of approximately $1.1 billion, and requested increases in various rates, including general system storage rates by 85% and general system transmission rates by 60%. In October 2021, the FERC issued an order that accepted the November 1, 2021 effective date for certain changes in rates, while suspending the other changes for five months following the proposed effective date, until April 1, 2022, subject to refund. In September 2022, a settlement agreement was filed with the FERC, which provided for increased service rates and decreased depreciation rates. Under the terms of the settlement agreement, EGTS' rates result in an increase to annual firm transmission and storage services revenues of approximately $160 million and a decrease in annual depreciation expense of approximately $30 million, compared to the rates in effect prior to April 1, 2022. EGTS' provision for rate refund for April 2022 through February 2023, including accrued interest, totaled $91 million. In November 2022, the FERC approved the settlement agreement and the rate refunds to customers were processed in late February 2023.

(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):

	2023	2022
Investments:		
Investment funds	$ 19	$ 14
Equity method investments:		
Iroquois	262	264
Total investments	281	278
Restricted cash and cash equivalents:		
Customer deposits	31	30
Total restricted cash and cash equivalents	31	30
Total investments and restricted cash and cash equivalents	$ 312	$ 308
Reflected as:		
Current assets	$ 31	$ 30
Noncurrent assets	281	278
Total investments and restricted cash and cash equivalents	$ 312	$ 308

Equity Method Investments

Eastern Energy Gas, through subsidiaries, owns 50% of Iroquois, which owns and operates an interstate natural gas pipeline located in the states of New York and Connecticut.

As of December 31, 2023 and 2022, 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 made contributions of $154 million in 2021. Eastern Energy Gas received distributions from its investments of $73 million, $195 million and $44 million for the years ended December 31, 2023, 2022 and 2021, 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

On June 30, 2021, as part of an intercompany transaction with its wholly owned subsidiary EGTS, Eastern Energy Gas exchanged a total of $1.6 billion of its issued and outstanding third-party notes, making EGTS the primary obligor of the exchanged notes. The intercompany debt exchange was a common control transaction accounted for as a debt modification with no gain or loss recognized on the Consolidated Financial Statements.

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):

	Par Value	2023	2022
Eastern Energy Gas:			
2.875% Senior Notes, due 2023	$ —	$ —	$ 250
3.55% Senior Notes, due 2023	—	—	399
2.50% Senior Notes, due 2024	600	600	598
3.60% Senior Notes, due 2024	339	339	338
3.32% Senior Notes, due 2026 (€250)(1)	276	274	267
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
EGTS:			
3.60% Senior Notes, due 2024	111	111	110
3.00% Senior Notes, due 2029	426	422	422
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	$ 3,276	$ 3,254	$ 3,892
Reflected as:			
Current portion of long-term debt		$ 1,050	$ 649
Long-term debt		2,204	3,243
Total long-term debt		$ 3,254	$ 3,892

(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, 2023 and 2022 that averaged 3.32%.

Eastern Energy Gas currently has an effective shelf registration statement with the U.S. Securities and Exchange Commission to issue up to $2.5 billion 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, 2024 and thereafter, are as follows (in millions):

2024	$ 1,050
2025	—
2026	276
2027	—
2028	—
2029 and thereafter	1,950
Total	3,276
Unamortized premium, discount and debt issuance cost	(22)
Total	$ 3,254

(9) Income Taxes

Income tax expense (benefit) consists of the following for the years ended December 31 (in millions):

	2023	2022	2021
Current:			
Federal	$ (236)	$ 12	$ (47)
State	(7)	29	(21)
	(243)	41	(68)
Deferred:			
Federal	357	88	129
State	(4)	38	56
	353	126	185
Total	$ 110	$ 167	$ 117

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:

	2023	2022	2021
Federal statutory income tax rate	21 %	21 %	21 %
State income tax, net of federal income tax benefit	(1)	6	3
Equity interest	2	2	1
Effects of ratemaking	—	(1)	1
Noncontrolling interest	(9)	(10)	(11)
Other, net	—	—	1
Effective income tax rate	13 %	18 %	16 %

For the year ended December 31, 2023, Eastern Energy Gas' reconciliation of the federal statutory income tax rate to the effective income tax rate is driven primarily by the absence of tax on noncontrolling interest.

The net deferred income tax liability consists of the following as of December 31 (in millions):

	2023	2022
Deferred income tax assets:		
Federal and state carryforwards	$ 22	$ 23
Employee benefits	29	22
Intangibles	98	112
Derivatives and hedges	13	16
Deferred state income taxes	24	—
Other	4	7
Total deferred income tax assets	190	180
Deferred income tax liabilities:		
Property-related items	(343)	(214)
Partnership investments	(158)	(51)
Debt exchange	(50)	(53)
Deferred state income taxes	—	(4)
Other	(5)	(12)
Total deferred income tax liabilities	(556)	(334)
Net deferred income tax liability[1]	$ (366)	$ (154)

(1) As of December 31, 2023 and 2022, net deferred income tax liability is presented in other assets and long-term liabilities in the Consolidated Balance Sheets.

As of December 31, 2023, Eastern Energy Gas' state tax carryforwards, entirely related to $22 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 $8 million, $14 million and $18 million of contributions to the MidAmerican Energy Company Retirement Plan for the years ended December 31, 2023, 2022 and 2021, respectively. Eastern Energy Gas made $2 million, $2 million and $10 million of contributions to the MidAmerican Energy Company Welfare Benefit Plan for the years ended December 31, 2023, 2022 and 2021, respectively. 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 participated in the BHE GT&S defined contribution employee savings plan. Effective April 1, 2023, 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. Certain participants now 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 $12 million, $6 million and $5 million for the years ended December 31, 2023, 2022 and 2021, 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. Cost of removal regulatory liabilities totaled $85 million and $82 million as of December 31, 2023 and 2022, respectively. Eastern Energy Gas will continue to monitor operational and strategic developments to identify if sufficient information exists to reasonably estimate a retirement date for these assets.

The following table reconciles the beginning and ending balances of Eastern Energy Gas' ARO liabilities for the years ended December 31 (in millions):

	2023	2022
Beginning balance	$ 48	$ 55
Additions	—	4
Retirements	(19)	(12)
Accretion	1	1
Ending balance	$ 30	$ 48
Reflected as:		
Other current liabilities	$ 5	$ 25
Other long-term liabilities	25	23
Total ARO liability	$ 30	$ 48

(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	2023	2022
Foreign currency	Euro €	250	250
Natural gas	Dth	6	3

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.

Upon the Cove Point LNG export/liquefaction facility commencing commercial operations, 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 38% of Eastern Energy Gas' operating revenues for the years ended December 31, 2023 and 2022, with Eastern Energy Gas' largest customer representing approximately 19% and 20% of such amounts, respectively.

For the year ended December 31, 2023, EGTS provided operational service to 250 customers with approximately 93% of its storage and transmission revenue being provided through firm services. The 10 largest customers provided approximately 40% of EGTS' total storage and transmission revenue and the thirty largest provided approximately 71% 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, 2023				
Assets:				
Money market mutual funds	$ 62	$ —	$ —	$ 62
Equity securities:				
Investment funds	19	—	—	19
	$ 81	$ —	$ —	$ 81
Liabilities:				
Foreign currency exchange rate derivatives	$ —	$ (8)	$ —	$ (8)
	$ —	$ (8)	$ —	$ (8)
As of December 31, 2022				
Assets:				
Commodity derivative	$ —	$ 1	$ —	$ 1
Money market mutual funds	42	—	—	42
Equity securities:				
Investment funds	14	—	—	14
	$ 56	$ 1	$ —	$ 57
Liabilities:				
Foreign currency exchange rate derivatives	$ —	$ (20)	$ —	$ (20)
	$ —	$ (20)	$ —	$ (20)

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):

	2023		2022	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 3,254	$ 2,968	$ 3,892	$ 3,510

(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. Plaintiffs occasionally seek punitive or exemplary damages. 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, 2023, Eastern Energy Gas had purchased $18 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):

	2023	2022	2021
Customer Revenue:			
Regulated:			
Gas transmission and storage	$ 1,210	$ 1,179	$ 1,044
Wholesale	22	8	57
Other	5	1	(2)
Total regulated	1,237	1,188	1,099
Nonregulated	818	821	767
Total Customer Revenue	2,055	2,009	1,866
Other revenue(1)	4	(3)	4
Total operating revenue	$ 2,059	$ 2,006	$ 1,870

(1) Other revenue consists primarily of revenue recognized in accordance with Accounting Standards Codification 815, "Derivative and Hedging" which includes unrealized gains and losses for derivatives not designated as hedges related to natural gas sales contracts 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, 2023 (in millions):

	Performance obligations expected to be satisfied		
	Less than 12 months	**More than 12 months**	**Total**
Eastern Energy Gas	$ 1,678	$ 14,687	$ 16,365

(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, 2020	$ (12)	$ (51)	$ 10	$ (53)
Other comprehensive income (loss)	6	9	(5)	10
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)

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
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	
2021			
Deferred (gains) and losses on derivatives-hedging activities:			
Interest rate contracts	$	6	Interest expense
Foreign currency contracts		21	Other, net
Total		27	
Tax		(7)	Income tax expense (benefit)
Total, net of tax	$	20	

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, 2023 (in millions):

	AOCI After-Tax		Amounts Expected to be Reclassified to Earnings During the Next 12 Months After-Tax		Maximum Term
Interest rate	$	(35)	$	(3)	252 months
Foreign currency		(3)		(2)	30 months
Total	$	(38)	$	(5)	

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, 2022, Eastern Energy Gas owned 100% of the general partner interest and 25% of the limited partner interest in Cove Point. As discussed in Note 3, on September 1, 2023, Eastern Energy Gas completed its acquisition of 50% of the limited partner interests in Cove Point from DEI, and accordingly, owns an aggregate of 75% of the limited partner interests and continues to own 100% of the general partner interest of Cove Point. Eastern Energy Gas concluded that Cove Point is a VIE due to the limited partners 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, $12 million and $12 million for the years ended December 31, 2023, 2022 and 2021, respectively. Effective April 2023, Carolina Gas Services no longer provides services to Eastern Energy Gas. Eastern Energy Gas' Consolidated Balance Sheets included amounts due to Carolina Gas Services of $1 million as of December 31, 2022. 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 DEI'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):

	2023	2022	2021
Supplemental disclosure of cash flow information:			
Interest paid, net of amounts capitalized	$ 144	$ 143	$ 144
Income taxes paid (received), net	$ 5	$ 2	$ (60)
Supplemental disclosure of non-cash investing and financing transactions:			
Accruals related to property, plant and equipment additions	$ 18	$ 29	$ 42
Equity distributions[1]	$ (224)	$ (42)	$ (137)
Equity contributions[1]	$ 38	$ 98	$ 73

(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 receivable from BHE of $67 million and $16 million as of December 31, 2023 and 2022, respectively. Eastern Energy Gas received net cash receipts for federal and state income taxes from BHE totaling $47 million for the year ended December 31, 2021.

As of December 31, 2022, Eastern Energy Gas had $1 million of natural gas imbalances payable to affiliates, presented in other current liabilities on the Consolidated Balance Sheets.

Presented below are Eastern Energy Gas' significant transactions with affiliated and related parties for the years ended December 31 (in millions):

	2023	2022	2021
Sales of natural gas and transmission and storage services	$ 5	$ 27	$ 32
Purchases of natural gas and transmission and storage services	—	4	5
Services provided by related parties[1]	99	83	51
Services provided to related parties	35	38	32

(1) Includes capitalized expenditures.

Eastern Energy Gas participates in certain MidAmerican Energy benefit plans as described in Note 10. As of December 31, 2023 and 2022, 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 $53 million and $51 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 2025. 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. Interest expense related to this borrowing totaled $4 million for the year ended December 31, 2023. There were no amounts outstanding under the credit agreement as of December 31, 2022.

BHE GT&S has a $650 million intercompany revolving credit agreement from Eastern Energy Gas expiring in November 2024. 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, 2023. As of December 31, 2022, $536 million was outstanding under the credit agreement. Interest income related to this borrowing totaled $20 million and $7 million for the years ended December 31, 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, 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 salaries, wages and benefits and higher technology and related charges, partially offset by lower income tax expense primarily due to favorable state tax adjustments.

Net income for the year ended December 31, 2022 was $261 million, an increase of $105 million, or 67%, compared to 2021, primarily due to higher margin from regulated gas transmission and storage operations of $128 million and a decrease due to the settlement of depreciation rates in EGTS' general rate case, partially offset by an increase in income tax expense primarily due to higher pre-tax income.

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 for 2023. 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.

Year Ended December 31, 2022 Compared to Year Ended December 31, 2021

Operating revenue increased $82 million, or 9%, for 2022 compared to 2021, primarily due to an increase in regulated gas transmission and storage services revenues due to the settlement of EGTS' general rate case of $101 million and an increase in variable revenue related to park and loan activity of $24 million, partially offset by a decrease in regulated gas sales for operational and system balancing purposes primarily due to decreased volumes of $49 million.

Cost of (excess) gas was a credit of $33 million for 2022 compared to an expense of $13 million for 2021. The change is primarily due to a decrease in volumes sold of $62 million, partially offset by unfavorable change to operational and system balancing volumes of $20 million.

Operations and maintenance decreased $12 million, or 3%, for 2022 compared to 2021, primarily due to a decrease in post-retirement benefit related costs.

Depreciation and amortization decreased $14 million, or 8%, for 2022 compared to 2021, primarily due to the settlement of depreciation rates in EGTS' general rate case of $23 million, partially offset by higher plant placed in-service of $9 million.

Property and other taxes decreased $8 million, or 13%, for 2022 compared to 2021, primarily due to lower than estimated 2021 tax assessments.

Disallowance and abandonment of utility plant was a credit of $11 million for 2021. The change is due to a 2021 benefit from the finalization of entries for the disallowance of capitalized AFUDC.

Interest expense decreased $9 million, or 12%, for 2022 compared to 2021, primarily due to lower expense of $44 million related to the elimination of long-term indebtedness to Eastern Energy Gas following the Debt Exchange Transaction in June 2021. These decreases were partially offset by $32 million of interest expense incurred under the senior notes issued in connection with that transaction, which bear lower interest rates than the original long-term indebtedness to Eastern Energy Gas.

Other, net was an expense of $2 million for 2022 compared to a credit of $2 million in 2021. The change is primarily due to losses on marketable securities.

Income tax expense increased $48 million, or 79%, for 2022 compared to 2021 and the effective tax rate was 29% in 2022 and 28% in 2021. The effective tax rate increased primarily due to the revaluation of deferred taxes from changes in various state income tax rates.

Liquidity and Capital Resources

As of December 31, 2023, EGTS' total net liquidity was as follows (in millions):

Cash and cash equivalents	$	5
Intercompany revolving credit agreement(1)		400
Less:		
Notes payable to affiliates		2
Net intercompany revolving credit agreement		398
Total net liquidity	$	403
Intercompany revolving credit agreement:		
Maturity date		2025

(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, 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.

Net cash flows from operating activities for the years ended December 31, 2022 and 2021 were $552 million and $367 million, respectively. The change was primarily due to the impacts from the proposed rate increase in effect April 1, 2022 for the EGTS general rate case, timing of income tax payments, higher collections of receivables from affiliates and other working capital adjustments.

The timing of EGTS' 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, 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.

Net cash flows from investing activities for the years ended December 31, 2022 and 2021 were $(286) million and $(357) million, respectively. The change was primarily due to a decrease in capital expenditures of $83 million and lower notes to affiliates of $6 million, partially offset by lower repayments of notes by affiliates of $8 million.

Financing Activities

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.

Net cash flows from financing activities for the year ended December 31, 2021 were $(7) million, primarily reflecting dividends paid of $18 million and the net repayment of notes payable to Eastern Energy Gas of $13 million, partially offset by a $20 million equity contribution from Eastern Energy Gas.

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%. As of December 31, 2022, EGTS had $36 million of an outstanding note payable to an affiliate at a weighted average interest rate of 1.43%. 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		
	2021	2022	2023	2024	2025	2026
Natural gas transmission and storage	$ 10	$ 35	$ 16	$ 17	$ 46	$ —
Other	348	240	225	250	222	261
Total	$ 358	$ 275	$ 241	$ 267	$ 268	$ 261

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, 2023 (in millions):

	Payments Due by Periods				
	2024	2025-2026	2027-2028	2029 and thereafter	Total
Interest payments on long-term debt[1]	$ 64	$ 121	$ 121	$ 813	$ 1,119
Natural gas supply and transmission[1]	46	92	93	26	257
Total cash requirements	$ 110	$ 213	$ 214	$ 839	$ 1,376

(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 $36 million and total regulatory liabilities were $545 million as of December 31, 2023. 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 2017 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, 2023, these amounts were recognized as a net regulatory liability of $377 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 commodity prices, 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.

Commodity Price Risk

As of February 2023, EGTS recovers its cost of gas through a fuel tracker and is no longer subject to significant commodity price risk.

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, 2023 and 2022, EGTS had short-term variable-rate obligations totaling $2 million and $36 million, respectively, 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, 2023 and 2022.

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, 2023, EGTS' credit exposure totaled $24 million. Of this amount, investment grade counterparties, including those internally rated, represented 100%, and no single counterparty, whether investment grade or non-investment grade, exceeded $5 million of exposure.

Item 8. Financial Statements and Supplementary Data

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, 2023 and 2022, 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, 2023, 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, 2023 and 2022, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2023, 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 audit 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 audit 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 ("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 future 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 23, 2024

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,	
	2023	2022
ASSETS		
Current assets:		
Cash and cash equivalents	$ 5	$ 16
Restricted cash and cash equivalents	29	29
Trade receivables, net	104	113
Receivables from affiliates	9	13
Inventories	59	50
Income taxes receivable	70	21
Prepayments and other deferred charges	22	36
Natural gas imbalances	34	193
Other current assets	5	9
Total current assets	337	480
Property, plant and equipment, net	4,715	4,504
Other assets	92	190
Total assets	$ 5,144	$ 5,174

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,	
	2023	2022
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities:		
Accounts payable	$ 41	$ 46
Accounts payable to affiliates	29	5
Accrued property, income and other taxes	58	71
Accrued employee expenses	20	13
Notes payable to affiliates	2	36
Regulatory liabilities	22	109
Customer and security deposits	29	29
Asset retirement obligations	5	25
Current portion of long-term debt	111	—
Other current liabilities	23	39
Total current liabilities	340	373
Long-term debt	1,472	1,582
Regulatory liabilities	523	518
Other long-term liabilities	121	101
Total liabilities	2,456	2,574
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	1,304	1,275
Retained earnings	803	746
Accumulated other comprehensive loss, net	(28)	(30)
Total shareholder's equity	2,688	2,600
Total liabilities and shareholder's equity	$ 5,144	$ 5,174

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,		
	2023	2022	2021
Operating revenue	$ 1,024	$ 973	$ 891
Operating expenses:			
Cost of (excess) gas	38	(33)	13
Operations and maintenance	404	364	376
Depreciation and amortization	151	152	166
Property and other taxes	50	54	62
Disallowance and abandonment of utility plant	—	—	(11)
Total operating expenses	643	537	606
Operating income	381	436	285
Other income (expense):			
Interest expense	(71)	(69)	(78)
Allowance for borrowed funds	1	1	2
Allowance for equity funds	5	4	6
Other, net	1	(2)	2
Total other income (expense)	(64)	(66)	(68)
Income (loss) before income tax expense (benefit)	317	370	217
Income tax expense (benefit)	79	109	61
Net income	$ 238	$ 261	$ 156

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,		
	2023	2022	2021
Net income	$ 238	$ 261	$ 156
Other comprehensive income (loss), net of tax:			
Unrealized gains (losses) on cash flow hedges, net of tax of $1, $1 and $(12)	2	1	(31)
Total other comprehensive income (loss), net of tax	2	1	(31)
Comprehensive income	$ 240	$ 262	$ 125

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 Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss, Net	Total Shareholder's Equity
	Shares	Amount				
Balance, December 31, 2020	60,101	$ 609	$ 929	$ 641	$ —	$ 2,179
Net income	—	—	—	156	—	156
Other comprehensive loss	—	—	—	—	(31)	(31)
Dividends declared	—	—	—	(76)	—	(76)
Contributions	—	—	312	—	—	312
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

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,		
	2023	**2022**	**2021**
Cash flows from operating activities:			
Net income	$ 238	$ 261	$ 156
Adjustments to reconcile net income to net cash flows from operating activities:			
(Gains) losses on other items, net	(8)	1	(8)
Depreciation and amortization	151	152	166
Allowance for equity funds	(5)	(4)	(6)
Changes in regulatory assets and liabilities	(76)	61	—
Deferred income taxes	119	92	93
Other, net	(8)	6	(7)
Changes in other operating assets and liabilities:			
Trade receivables and other assets	15	(14)	(28)
Receivables from affiliates	4	(4)	(46)
Gas balancing activities	27	(31)	76
Pension and other postretirement benefit plans	—	—	(17)
Accrued property, income and other taxes	(57)	18	(23)
Accounts payable to affiliates	24	(8)	11
Accounts payable and other liabilities	(6)	22	—
Net cash flows from operating activities	418	552	367
Cash flows from investing activities:			
Capital expenditures	(241)	(275)	(358)
Proceeds from assignment of shale development rights	8	—	—
Notes to affiliates	—	(8)	(14)
Repayment of notes by affiliates	—	11	19
Other, net	(4)	(14)	(4)
Net cash flows from investing activities	(237)	(286)	(357)
Cash flows from financing activities:			
Repayment of notes payable to affiliates, net	(34)	(32)	(13)
Proceeds from equity contributions	—	—	20
Dividends paid	(158)	(215)	(18)
Other, net	—	—	4
Net cash flows from financing activities	(192)	(247)	(7)
Net change in cash and cash equivalents and restricted cash and cash equivalents	(11)	19	3
Cash and cash equivalents and restricted cash and cash equivalents at beginning of period	45	26	23
Cash and cash equivalents and restricted cash and cash equivalents at end of period	$ 34	$ 45	$ 26

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 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 owns subsidiaries principally engaged in the energy industry. BHE is a consolidated 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, 2023 and 2022, 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,	
	2023	**2022**
Cash and cash equivalents	$ 5	$ 16
Restricted cash and cash equivalents	29	29
Total cash and cash equivalents and restricted cash and cash equivalents	$ 34	$ 45

Allowance for Credit Losses

Trade receivables are primarily short-term in nature 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 evaluates the financial condition of the individual customer and the nature of any disputed amount.

The changes in the balance of the allowance for credit losses, which is included in trades receivables, net on the Consolidated Balance Sheets, is summarized as follows for the years ended December 31, (in millions):

	2023	**2022**	**2021**
Beginning balance	$ —	$ 3	$ 2
Charged to operating costs and expenses, net	—	—	1
Write-offs, net	—	(3)	—
Ending balance	$ —	$ —	$ 3

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 natural gas pipeline 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 and finance leases consisting primarily of natural gas pipeline facilities and vehicles. 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 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

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. As of December 31, 2023 and 2022, trade receivables, net on the Consolidated Balance Sheets relate substantially to Customer Revenue, including unbilled revenue of $17 million and $9 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, 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 $8 million and $10 million as of December 31, 2023 and 2022, respectively, and $2 million and $9 million of contract liabilities as of December 31, 2023 and 2022, 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 segment, which includes its natural gas pipeline and storage operations.

New Accounting Pronouncements

In November 2023, the FASB issued 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 is currently evaluating the impact of adopting this guidance on its 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.

(3) Property, Plant and Equipment, Net

Property, plant and equipment, net consists of the following as of December 31 (in millions):

	Depreciable Life	2023	2022
Interstate natural gas transmission and storage assets	28 - 50 years	$ 7,046	$ 6,724
Intangible plant	12 - 20 years	80	79
Plant in-service		7,126	6,803
Accumulated depreciation and amortization		(2,563)	(2,440)
		4,563	4,363
Construction work-in-progress		152	141
Property, plant and equipment, net		$ 4,715	$ 4,504

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, 2023 (dollars in millions):

	EGTS' Share	Facility in Service	Accumulated Depreciation and Amortization	Construction Work-in-Progress
Ellisburg Pool	39 %	$ 33	$ 12	$ —
Ellisburg Station	50	29	9	2
Harrison	50	56	19	1
Leidy	50	148	49	2
Oakford	50	216	73	4
Total		$ 482	$ 162	$ 9

(5) Leases

The following table summarizes EGTS' leases recorded on the Consolidated Balance Sheets as of December 31 (in millions):

	2023	2022
Right-of-use assets:		
Operating leases	$ 18	$ 19
Total right-of-use assets	$ 18	$ 19
Lease liabilities:		
Operating leases	$ 17	$ 18
Total lease liabilities	$ 17	$ 18

The following table summarizes EGTS' operating lease costs for the years ended December 31 (in millions):

	2023	2022	2021
Total operating lease costs	$ 2	$ 2	$ 3
Weighted-average remaining operating lease term (years)	12.7	13.7	14.7
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):

	2023	2022	2021
Cash paid for amounts included in the measurement of lease liabilities:			
Operating cash flows from operating leases	$ 2	$ 2	$ 3
Operating cash flows from finance leases	—	—	1

EGTS has the following remaining operating lease commitments as of December 31, 2023 (in millions):

2024	$ 2
2025	2
2026	2
2027	2
2028	2
Thereafter	12
Total undiscounted lease payments	22
Less - amounts representing interest	(5)
Lease liabilities	$ 17

(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	2023	2022
Employee benefit plans[(1)]	11 years	$ 32	$ 31
Other	Various	4	8
Total regulatory assets		$ 36	$ 39
Reflected as:			
Other current assets		$ 3	$ 5
Other assets		33	34
Total regulatory assets		$ 36	$ 39

(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 $36 million and $39 million as of December 31, 2023 and 2022, 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	2023	2022
Income taxes refundable through future rates(1)	Various	$ 377	$ 382
Other postretirement benefit costs(2)	Various	124	123
Provision for rate refunds(3)		—	90
Cost of removal(4)	47 years	28	24
Other	Various	16	8
Total regulatory liabilities		$ 545	$ 627
Reflected as:			
Current liabilities		$ 22	$ 109
Noncurrent liabilities		523	518
Total regulatory liabilities		$ 545	$ 627

(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) Reflects amounts refunded to customers in late February 2023 in connection with the EGTS rate case. See below for more information.

(4) 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

In September 2021, EGTS filed a general rate case for its FERC-jurisdictional services, with proposed rates to be effective November 1, 2021. EGTS proposed an annual cost-of-service of approximately $1.1 billion, and requested increases in various rates, including general system storage rates by 85% and general system transmission rates by 60%. In October 2021, the FERC issued an order that accepted the November 1, 2021 effective date for certain changes in rates, while suspending the other changes for five months following the proposed effective date, until April 1, 2022, subject to refund. In September 2022, a settlement agreement was filed with the FERC, which provided for increased service rates and decreased depreciation rates. Under the terms of the settlement agreement, EGTS' rates result in an increase to annual firm transmission and storage services revenues of approximately $160 million and a decrease in annual depreciation expense of approximately $30 million, compared to the rates in effect prior to April 1, 2022. EGTS' provision for rate refund for April 2022 through February 2023, including accrued interest, totaled $91 million. In November 2022, the FERC approved the settlement agreement and the rate refunds to customers were processed in late February 2023.

In July 2017, the FERC audit staff communicated to EGTS that it had substantially completed an audit of EGTS' compliance with the accounting and reporting requirements of the FERC's Uniform System of Accounts and provided a description of matters and preliminary recommendations. In November 2017, the FERC audit staff issued its audit report. In December 2017, EGTS provided its response to the audit report. EGTS requested FERC review of the contested findings and submitted its plan for compliance with the uncontested portions of the report. EGTS reached resolution of certain matters with the FERC in the fourth quarter of 2018. EGTS recognized a charge for a disallowance of plant, originally established beginning in 2012, for the resolution of one matter with the FERC. In December 2020, the FERC issued a final ruling on the remaining matter, which resulted in a $43 million ($31 million after-tax) estimated charge for disallowance of capitalized AFUDC. As a condition of the December 2020 ruling, EGTS filed its proposed accounting entries and supporting documentation with the FERC during the second quarter of 2021. During the finalization of these entries, EGTS refined the estimated charge for disallowance of capitalized AFUDC, which resulted in a reduction to the estimated charge of $11 million ($8 million after-tax) that was recorded in disallowance and abandonment of utility plant on the Consolidated Statement of Operations in the second quarter of 2021. In September 2021, the FERC approved EGTS' accounting entries and supporting documentation.

(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):

	2023	2022
Investments:		
Investment funds	$ 19	$ 14
Restricted cash and cash equivalents:		
Customer deposits	29	29
Total restricted cash and cash equivalents	29	29
Total investments and restricted cash and cash equivalents	$ 48	$ 43
Reflected as:		
Current assets	$ 29	$ 29
Other assets	19	14
Total investments and restricted cash and cash equivalents	$ 48	$ 43

(8) Long-term Debt

On June 30, 2021, Eastern Energy Gas exchanged a total of $1.6 billion of its issued and outstanding third-party notes for new notes, making EGTS the primary obligor of the new notes. The terms of the new notes are substantially similar to the terms of the original Eastern Energy Gas notes. The debt exchange was a common control transaction accounted for as a debt modification. As such, no gain or loss was recognized on the Consolidated Statements of Operations and approximately $17 million of unamortized discounts and debt issuance costs and $32 million of deferred losses on previously settled interest rate swaps remaining in AOCI were contributed to EGTS by Eastern Energy Gas in connection with the transaction. In addition, new fees of $2 million paid directly to note holders in connection with the exchange were deferred as additional debt issuance costs that will be amortized over the lives of the respective notes. As a result of the transaction, EGTS' $1.9 billion of long-term indebtedness to Eastern Energy Gas was cancelled in full and the remaining balance was satisfied through a capital contribution.

EGTS' long-term debt consists of the following, including unamortized discounts and debt issuance costs, as of December 31 (dollars in millions):

	Par Value	2023	2022
3.60% Senior Notes, due 2024	$ 111	$ 111	$ 110
3.00% Senior Notes, due 2029	426	422	422
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	$ 1,600	$ 1,583	$ 1,582
Reflected as:			
Current portion of long-term debt		$ 111	$ —
Long-term debt		1,472	1,582
Total long-term debt		$ 1,583	$ 1,582

Annual Payment on Long-Term Debt

The annual repayments of long-term debt for the years beginning January 1, 2024 and thereafter, are as follows (in millions):

2024	$ 111
2025	—
2026	—
2027	—
2028	—
2029 and thereafter	1,489
Total	1,600
Unamortized discounts and debt issuance costs	(17)
Total	$ 1,583

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, 2023 (in millions):

	AOCI After-Tax	Amounts Expected to be Reclassified to Earnings During the Next 12 Months After-Tax	Maximum Term
Interest rate	$ (28)	$ (2)	252 months

EGTS reclassified $3 million, $2 million and $1 million from AOCI to interest expense for the years ended December 31, 2023, 2022 and 2021, respectively.

(9) Income Taxes

Income tax expense (benefit) consists of the following for the years ended December 31 (in millions):

	2023	2022	2021
Current:			
Federal	$ (28)	$ 5	$ (22)
State	(12)	12	(10)
	(40)	17	(32)
Deferred:			
Federal	91	64	67
State	28	28	26
	119	92	93
Total	$ 79	$ 109	$ 61

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:

	2023	2022	2021
Federal statutory income tax rate	21 %	21 %	21 %
State income tax, net of federal income tax benefit	4	9	8
Other, net	—	(1)	(1)
Effective income tax rate	25 %	29 %	28 %

The net deferred income tax (liability) asset consists of the following as of December 31 (in millions):

	2023	2022
Deferred income tax assets:		
Federal and state carryforwards	$ 5	$ 6
Employee benefits	26	22
Intangibles and goodwill	252	265
Derivatives and hedges	10	11
Other	5	4
Total deferred income tax assets	298	308
Deferred income tax liabilities:		
Property-related items	(264)	(146)
Debt exchange	(50)	(53)
Employee benefits	—	(4)
Total deferred income tax liabilities	(314)	(203)
Net deferred income tax (liability) asset(1)	$ (16)	$ 105

(1) 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, 2022, net deferred income tax assets is presented in other assets in the Consolidated Balance Sheets.

As of December 31, 2023, EGTS' state tax carryforwards, entirely related to $5 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, $12 million and $16 million of contributions to the MidAmerican Energy Company Retirement Plan for the years ended December 31, 2023, 2022 and 2021, respectively. EGTS made $2 million, $2 million and $9 million of contributions to the MidAmerican Energy Company Welfare Benefit Plan for the years ended December 31, 2023, 2022 and 2021, respectively. 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 participated in the BHE GT&S defined contribution employee savings plan. Effective April 1, 2023, 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. Certain participants now receive enhanced benefits in the plan and no longer accrue benefits in the noncontributory defined benefit pension plans. EGTS' contributions to the plans were $9 million, $5 million and $4 million for the years ended December 31, 2023, 2022 and 2021, 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. Cost of removal regulatory liabilities totaled $28 million and $24 million as of December 31, 2023 and 2022, respectively. EGTS will continue to monitor operational and strategic developments to identify if sufficient information exists to reasonably estimate a retirement date for these assets.

The following table reconciles the beginning and ending balances of EGTS' ARO liabilities for the years ended December 31 (in millions):

	2023	2022
Beginning balance	$ 48	$ 55
Additions	—	4
Retirements	(19)	(12)
Accretion	1	1
Ending balance	$ 30	$ 48
Reflected as:		
Current liabilities	$ 5	$ 25
Other long-term liabilities	25	23
Total ARO liability	$ 30	$ 48

(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, 2023, the 10 largest customers provided 40% 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, 2023				
Assets:				
Money market mutual funds	$ 5	$ —	$ —	$ 5
Equity securities:				
Investment funds	19	—	—	19
	$ 24	$ —	$ —	$ 24
As of December 31, 2022				
Assets:				
Commodity derivatives	$ —	$ 1	$ —	$ 1
Money market mutual funds	8	—	—	8
Equity securities:				
Investment funds	14	—	—	14
	$ 22	$ 1	$ —	$ 23

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):

	2023		2022	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 1,583	$ 1,386	$ 1,582	$ 1,337

(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. Plaintiffs occasionally seek punitive or exemplary damages. 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, 2023, 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):

	2023	2022	2021
Customer Revenue:			
Regulated:			
Gas transmission	$ 656	$ 644	$ 574
Gas storage	274	248	188
Wholesale	22	8	57
Other	2	—	—
Total regulated	954	900	819
Management services and other revenues	66	79	73
Total Customer Revenue	1,020	979	892
Other revenue(1)	4	(6)	(1)
Total operating revenue	$ 1,024	$ 973	$ 891

(1) Other revenue consists primarily of revenue recognized in accordance with Accounting Standards Codification 815, "Derivative and Hedging" which includes unrealized gains and losses for derivatives not designated as hedges related to natural gas sales contracts 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, 2023 (in millions):

	Performance obligations expected to be satisfied		
	Less than 12 months	More than 12 months	Total
EGTS	$ 794	$ 3,346	$ 4,140

(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):

	2023	2022	2021
Supplemental disclosure of cash flow information:			
Interest paid, net of amounts capitalized	$ 69	$ 67	$ 71
Income taxes paid (received), net	$ 5	$ 2	$ (12)
Supplemental disclosure of non-cash investing and financing transactions:			
Accruals related to property, plant and equipment additions	$ 9	$ 15	$ 29
Equity dividends(1)	$ (23)	$ (21)	$ (58)
Equity contributions(2)	$ 29	$ 34	$ 292

(1) Equity dividends represents the forgiveness of affiliated receivables.

(2) Equity contributions for the year ended December 31, 2021 primarily reflect the impacts from the intercompany debt exchange with Eastern Energy Gas. See Note 8 for more information regarding the intercompany debt exchange with Eastern Energy Gas.

(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 receivable from BHE of $57 million and $21 million as of December 31, 2023 and 2022, respectively. EGTS received net cash receipts for federal and state income taxes from BHE totaling $10 million for the year ended December 31, 2021.

Trade receivables, net as of December 31, 2022 included $2 million of accrued unbilled revenue. This revenue is based on estimated amounts of services provided but not yet billed to an affiliate.

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. As of December 31, 2022, EGTS had $10 million of natural gas imbalances payable to affiliates, presented in other current liabilities on the Consolidated Balance Sheets.

EGTS participates in certain MidAmerican Energy benefit plans as described in Note 10. As of December 31, 2023 and 2022, EGTS' amount due to MidAmerican Energy associated with these plans and reflected in other long-term liabilities on the Consolidated Balance Sheets was $48 million and $47 million, respectively.

Presented below are EGTS' significant transactions with related parties for the years ended December 31 (in millions):

	2023	2022	2021
Sales of natural gas and transmission and storage services	$ 4	$ 26	$ 28
Purchases of natural gas and transmission and storage services	—	4	5
Services provided by related parties(1)	58	46	26
Services provided to related parties	59	62	57

(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 2025. 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 and $36 million with a weighted-average interest rate of 1.43% as of December 31, 2022. Interest expense related to this borrowing 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 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, 2023 and 2022. Interest income related to this borrowing totaled $2,071 for the year ended December 31, 2021.

EGTS had also borrowed from Eastern Energy Gas pursuant to a series of long-term notes with fixed interest rates ranging from 3.6% to 5.0%, due 2024 to 2047. EGTS incurred interest charges related to these borrowings of $44 million for the year ended December 31, 2021. Refer to Note 8 for more information.

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, 2023 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, 2023, 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, 2023.

Berkshire Hathaway Energy Company February 23, 2024	PacifiCorp February 23, 2024	MidAmerican Funding, LLC February 23, 2024
MidAmerican Energy Company February 23, 2024	Nevada Power Company February 23, 2024	Sierra Pacific Power Company February 23, 2024
Eastern Energy Gas Holdings, LLC February 23, 2024	Eastern Gas Transmission and Storage, Inc. February 23, 2024	

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

BERKSHIRE HATHAWAY ENERGY, 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.

PACIFICORP

PacifiCorp is an indirect subsidiary of BHE, and its directors consist of executive management from both BHE and PacifiCorp. Each director was elected based on individual responsibilities, experience in the energy industry and functional expertise. There are no family relationships among the executive officers, nor any arrangements or understandings between any executive officer and any other person pursuant to which the executive officer was appointed. Set forth below is certain information, as of January 31, 2024, with respect to the current directors and executive officers of PacifiCorp:

CINDY A. CRANE, 62, Chair of the Board of Directors and Chief Executive Officer since September 2023. Prior to her current positions, Ms. Crane served as President and Chief Executive Officer of Rocky Mountain Power from 2014 and director from 2015 to 2018. Ms. Crane was Vice President of Interwest Mining Company, a subsidiary of PacifiCorp, from 2009 to 2014. Ms. Crane joined PacifiCorp in 1990 and has significant strategy, operational and leadership experience in the energy industry, including complex commercial negotiations.

GARY W. HOOGEVEEN, 55, Director since November 2018, President since June 2018 and Chief Executive Officer since November 2018 of Rocky Mountain Power. Prior to his current positions, Mr. Hoogeveen served as Senior Vice President and Chief Commercial Officer of Rocky Mountain Power since November 2014 and President and CEO of Kern River Gas Transmission Company from 2010 to 2014. He joined Kern River after serving as Vice President of Customer Service and Business Development for Northern Natural Gas Company. Prior to joining Northern Natural Gas Company, Mr. Hoogeveen held various management positions at Berkshire Hathaway Energy, joining BHE in 2000. He has significant operational, public policy and leadership experience in both the electricity and natural gas industries, including customer, regulatory and government relations.

NIKKI L. KOBLIHA, 51, Director since 2017. Vice President and Chief Financial Officer since 2015 and Treasurer since 2017. Ms. Kobliha joined PacifiCorp in 1997 and has significant financial, accounting and leadership experience in the energy industry, including expertise in financial reporting to the SEC and FERC.

CALVIN D. HAACK, 55, Director since May 2020. Mr. Haack has been Senior Vice President and Chief Financial Officer of BHE since March 2020 and was Vice President and Treasurer of BHE from 2010 to 2020. Mr. Haack joined BHE in 1997 and has significant financial experience, including expertise in mergers and acquisitions, accounting, treasury and tax functions. Mr. Haack is also a manager of MidAmerican Funding, LLC and Eastern Energy Gas Holdings, LLC.

NATALIE L. HOCKEN, 54, Director since 2007. Ms. Hocken has been Senior Vice President and General Counsel of BHE since 2015 and Corporate Secretary since 2017. Ms. Hocken was Senior Vice President, Transmission and System Operations of PacifiCorp from 2012 to 2015 and Vice President and General Counsel of Pacific Power from 2007 to 2012. Ms. Hocken joined PacifiCorp in 2002 and has significant experience in the utility industry, including expertise in transmission, legal matters and federal and state regulatory matters. Ms. Hocken is also a manager of MidAmerican Funding, LLC and Eastern Energy Gas Holdings, LLC.

Board's Role in the Risk Oversight Process

PacifiCorp's Board of Directors is comprised of a combination of BHE senior executives and PacifiCorp senior management who have direct and indirect responsibility for the management and oversight of risk. PacifiCorp's Board of Directors has not established a separate risk management and oversight committee.

Audit Committee and Audit Committee Financial Expert

During the year ended December 31, 2023, and as of the date of this Annual Report on Form 10-K, PacifiCorp's Board of Directors did not have an audit committee. PacifiCorp is not required to have an audit committee as its common stock is indirectly and wholly owned by BHE. However, the audit committee of BHE acts as the audit committee for PacifiCorp.

Code of Ethics

PacifiCorp has adopted a code of ethics that applies to its principal executive officer, its principal financial and accounting officer, or persons acting in such capacities, and certain other covered officers. The code of ethics is incorporated by reference in the exhibits to this Annual Report on Form 10-K.

Item 11. Executive Compensation

BERKSHIRE HATHAWAY ENERGY, 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.

PACIFICORP

Compensation Discussion and Analysis

Compensation Philosophy and Overall Objectives

On September 1, 2023, Mr. Scott W. Thon resigned as PacifiCorp's Chair ("Chair") of the Board of Directors (the "Board") and Chief Executive Officer ("CEO") and Ms. Cindy A. Crane was elected as PacifiCorp's Chair and CEO. Mr. Thon did not receive any direct compensation from PacifiCorp in 2023. Rather, PacifiCorp reimbursed its indirect parent company, BHE, for the cost of Mr. Thon's time spent on matters supporting PacifiCorp, including compensation paid to him by BHE, pursuant to an intercompany administrative services agreement among BHE and its subsidiaries. As an employee of PacifiCorp, Ms. Crane receives direct compensation from PacifiCorp.

PacifiCorp believes that the compensation paid to its CEO, Chief Financial Officer ("CFO"), and its other most highly compensated executive officers, referred to collectively as the Named Executive Officers ("NEOs"), should be closely aligned with PacifiCorp's overall performance, and each NEO's contribution to that performance, on both a short- and long-term basis, and that such compensation should be sufficient to attract and retain highly qualified leaders who can create significant value for the organization. PacifiCorp's compensation programs are designed to provide its NEOs meaningful incentives for superior corporate and individual performance. Performance is evaluated on a subjective basis within the context of both financial and non-financial objectives, among which are customer service, employee commitment, environmental respect, regulatory integrity, operational excellence and financial strength, which PacifiCorp believes contribute to its long-term success.

How Compensation is Determined

PacifiCorp's compensation committee consists solely of the Chair and CEO. The Chair and CEO is responsible for the establishment and oversight of PacifiCorp's compensation policy and for approving compensation decisions for the other NEOs, such as approving their base pay increases, incentive and performance awards, off-cycle pay changes, and participation in other employee benefit plans and programs.

PacifiCorp's criteria for assessing executive performance and determining compensation in any year is inherently subjective and is not based upon specific formulas or weighting of factors. PacifiCorp does not specifically use other companies as benchmarks when establishing its NEOs' compensation.

Discussion and Analysis of Specific Compensation Elements

Base Salary

The Chair and CEO determines base salaries for all of its NEOs, other than the Chair and CEO, by reviewing PacifiCorp's overall performance, and each NEO's performance, the value each NEO brings to PacifiCorp and general labor market conditions. Base salary is intended to compensate NEOs for services rendered during the fiscal year and to provide sufficient cash income for retention and recruitment purposes. While base salary provides a base level of compensation intended to be competitive with the external market, the annual base salary adjustment for each NEO, other than the Chair and CEO, is determined on a subjective basis after consideration of these factors and is not based on target percentiles or other formal criteria. All merit increases for the NEOs (other than the Chair and CEO) are approved by the Chair and CEO and take effect in the last payroll period of the year. An increase or decrease in base salary may also result from a promotion or other significant change in an NEO's responsibilities during the year. For 2023, base salaries for all NEOs, other than the Chair and CEO, increased on average by 3.20% from the previous year effective December 26, 2022, reflecting merit increases. Ms. Crane's base salary for her role as CEO is based upon her offer of employment.

Short-Term Incentive Compensation

The objective of short-term incentive compensation is to reward the achievement of significant annual corporate and business unit goals while also providing NEOs with competitive total cash compensation. PacifiCorp's short-term incentive compensation programs consist of the Annual Incentive Plan and Cash Performance Awards as described below.

Annual Incentive Plan

Under PacifiCorp's Annual Incentive Plan ("AIP"), all NEOs, other than the Chair and CEO and CFO, are eligible to earn an annual discretionary cash incentive award, which is determined on a subjective basis at the Chair and CEO's sole discretion and is not based on a specific formula or cap. The Chair and CEO considers a variety of factors in determining each NEO's annual incentive award including the NEO's performance, PacifiCorp's overall performance and each NEO's contribution to that overall performance. The Chair and CEO evaluates performance holistically using a number of objectives, including customer service, employee commitment, environmental respect, regulatory integrity, operational excellence and financial strength, as well as the NEO's response to issues and opportunities that arise during the year. No factor was individually material to the Chair and CEO's determination regarding the amounts paid to each NEO under the AIP for 2023. Approved awards are paid prior to year-end.

Cash Performance Awards

In addition to the annual awards under the AIP, PacifiCorp may grant cash performance awards ("Cash Performance Awards") periodically during the year to one or more NEOs, other than the Chair and CEO, to reward the accomplishment of significant non-recurring tasks or projects. These awards are discretionary and are approved by the Chair and CEO. No Cash Performance Awards were earned by the NEOs during 2023.

Long-Term Incentive Compensation

The objective of long-term incentive compensation is to retain NEOs, reward their exceptional performance and motivate them to create long-term, sustainable value. PacifiCorp's current long-term incentive compensation program is cash-based. PacifiCorp does not utilize stock options or other forms of equity-based awards.

Long-Term Incentive Partnership Plan

The PacifiCorp Long-Term Incentive Partnership Plan ("LTIP") is designed to retain key employees and to align PacifiCorp's interests and the interests of the participating employees. All of PacifiCorp's NEOs, other than the Chair and CEO and CFO, are eligible to participate in the LTIP. The LTIP provides for annual discretionary awards based upon significant accomplishments by the individual participants and the achievement of the holistic objectives previously described. The goals are developed with the objective of being attainable with a sustained, focused and concerted effort and are determined and communicated by January of each plan year. The BHE President and CEO and PacifiCorp's Presidents approve eligibility to participate in the LTIP for employees other than the Presidents and the amount of the incentive award. Awards are finalized in the first quarter of the following year. PacifiCorp's Presidents may participate in the LTIP but only the BHE President and CEO shall make determinations regarding their participation and the value of their incentive awards. These cash-based LTIP awards are subject to mandatory deferral and equal annual vesting over a four-year period starting in the performance year. Participants allocate the value of their deferral accounts among various investment alternatives. Gains or losses may be incurred based on investment performance. Participating NEOs may elect to defer all or a part of the award or receive payment in cash after the four-year mandatory deferral and vesting period. Vested balances (including any investment gains or losses thereon) of terminating participants are paid at the time of termination. No amounts were awarded to the NEOs under the LTIP for the 2023 performance period.

Critical Personnel Agreements

Beginning in 2023, PacifiCorp entered into Critical Personnel Agreements with certain key employees, including the CFO, who possess skills that are important to the continued success of PacifiCorp. These agreements provide for cash amounts to be awarded to the employee in four installment payments to be made at specified dates as long as the employee is in good standing in the defined position as of December 31 each year within the award period. Amounts awarded under the Critical Personnel Agreements are in lieu of AIP and LTIP awards. The agreements do not constitute a guarantee of future employment.

Deferred Compensation Plan

PacifiCorp's Executive Voluntary Deferred Compensation Plan ("DCP") provides a means for all NEOs, other than Mr. Thon, to make voluntary deferrals of up to 50% of their base salary and 100% of their short-term incentive compensation awards. PacifiCorp includes the DCP as part of the participating NEO's overall compensation in order to provide a comprehensive, competitive package. The deferrals and any investment returns grow on a tax-deferred basis. Amounts deferred under the DCP receive a rate of return based on the returns of any combination of various investment alternatives offered under the DCP and selected by the participant. The DCP allows participants to choose from three forms of distribution. The DCP permits PacifiCorp to make discretionary contributions on behalf of participants; however, no such contributions were made in 2023.

Potential Payments Upon Termination

PacifiCorp's NEOs are generally not entitled to severance or enhanced benefits upon termination of employment or change in control. None of PacifiCorp's NEOs have a formal employment agreement or offer letter with termination provisions; therefore, payments upon termination are determined by the applicable plan documents, applicable Critical Personnel Agreements, and PacifiCorp's general employment policies and practices as discussed below.

Compensation Committee Report

Ms. Crane, PacifiCorp's current Chair and CEO and sole member of PacifiCorp's compensation committee, has reviewed the Compensation Discussion and Analysis and, based on her review, has recommended to the Board of Directors that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K.

Cindy A. Crane

Summary Compensation Table

The following table sets forth information regarding compensation earned by each of PacifiCorp's NEOs during the years indicated:

Name and Principal Position	Year	Salary	Bonus [1]	Change in Pension Value and Nonqualified Deferred Compensation Earnings[2]	All Other Compensation [3]	Total [4]
Cindy A. Crane[7]	2023	$ 633,338	$ —	$ 55,008	$ 243,371	$ 931,717
Chair of the Board of Directors	2022	—	—	—	—	—
and Chief Executive Officer	2021	—	—	—	—	—
Scott W. Thon[5][6][7]	2023	—	—	—	—	—
Chair of the Board of Directors	2022	—	—	—	—	—
and Chief Executive Officer	2021	—	—	—	—	—
Stefan A. Bird[8]	2023	525,500	600,252	46,490	41,250	1,213,492
President and Chief Executive	2022	510,000	1,134,275	—	41,525	1,685,800
Officer, Pacific Power	2021	473,011	1,142,660	—	33,010	1,648,681
Gary W. Hoogeveen	2023	525,500	857,373	—	42,316	1,425,189
President and Chief Executive	2022	510,000	881,112	—	41,979	1,433,091
Officer, Rocky Mountain Power	2021	473,011	1,066,924	—	33,010	1,572,945
Nikki L. Kobliha	2023	301,446	563,478	11,518	31,476	907,918
Vice President, Chief Financial	2022	282,182	259,110	—	37,131	578,423
Officer and Treasurer	2021	262,260	396,880	—	32,651	691,791

(1) The amounts shown under "Bonus" for year 2023 consists of annual cash incentive awards earned pursuant to the AIP for PacifiCorp's NEOs, amounts earned under applicable Critical Personnel Agreements, Cash Performance Awards and the vesting of LTIP awards and associated vested earnings. No Cash Performance Awards were awarded to the NEOs during 2023. The breakout for 2023 is as follows:

			LTIP			
	AIP	Critical Personnel Award	Vested Awards	Vested Earnings	Total LTIP	Total
Stefan A. Bird	$ —	$ —	$ 485,000	$ 115,252	$ 600,252	$ 600,252
Gary W. Hoogeveen	272,419	—	411,250	173,704	584,954	857,373
Nikki L. Kobliha	—	380,027	120,000	63,451	183,451	563,478

The ultimate payouts of LTIP awards are undeterminable as the amounts to be paid out may increase or decrease depending on investment performance. The BHE President and CEO and PacifiCorp's Presidents have historically established the award categories for determining LTIP awards based on net income target goals or other criteria.

(2) Amounts are based upon the aggregate change in the actuarial present value of all qualified and nonqualified defined benefit plans, which includes the Retirement Plan. Refer to the Pension Benefits table below for a discussion of the assumptions used in calculating these amounts. No participant in PacifiCorp's nonqualified deferred compensation plans earned "above market" or "preferential" earnings on amounts deferred.

(3) The amounts shown for "All Other Compensation" for year 2023 consist of PacifiCorp K Plus Employee Savings Plan, or 401(k) Plan, contributions PacifiCorp paid on behalf of the NEOs, except for Ms. Crane who had $166,668 in relocation allowance, $29,506 in relocation expenses (plus $14,197 in tax gross-up), and for Mr. Hoogeveen and Ms. Kobliha for whom PacifiCorp also includes an amount paid for a tax gross-up with respect to a personal benefit with a value less than $10,000.

(4) Any amounts voluntarily deferred by the NEO, if applicable, are included in the appropriate column in the Summary Compensation Table.

(5) On April 13, 2022, Mr. Scott W. Thon was elected as PacifiCorp's Chair of the Board of Directors and Chief Executive Officer, replacing Mr. William J. Fehrman who concurrently resigned as PacifiCorp's Chair of the Board of Directors and Chief Executive Officer.

(6) In 2023, PacifiCorp reimbursed BHE $303,807 for the cost of Mr. Thon's time spent on matters supporting PacifiCorp pursuant to the intercompany administrative services agreement.

(7) On September 1, 2023, Mr. Scott W. Thon resigned as PacifiCorp's Chair of the Board of Directors and Chief Executive Officer and Ms. Cindy A. Crane was elected as PacifiCorp's Chair of the Board of Directors and Chief Executive Officer to replace Mr. Thon in such capacities.

(8) On January 2, 2024, Mr. Stefan A. Bird resigned as Pacific Power's President and Chief Executive Officer.

Pension Benefits

The following table sets forth certain information regarding the defined benefit pension plan accounts held by each of PacifiCorp's NEOs as of December 31, 2023:

Name	Plan name	Number of years of credited service	Present value of accumulated benefits [1]
Cindy A. Crane	Retirement	21 years	$ 534,185
Stefan A. Bird	Retirement	10 years	247,002
Gary W. Hoogeveen	n/a	n/a	n/a
Nikki L. Kobliha	Retirement	12 years	110,413

(1) Amounts are computed using assumptions, other than the expected retirement age, consistent with those used in preparing the related pension disclosures in the Notes to Consolidated Financial Statements of PacifiCorp in Item 8 of this Form 10-K and are as of December 31, 2023, which is the measurement date for the plans. The expected retirement age assumption has been determined in accordance with Instruction 2 to Item 402(h)(2) of Regulation S-K. For the Retirement Plan calculations of the present value of accumulated benefits, the following assumptions were used: 60% lump sum payment; 40% joint and 100% survivor annuity if participant is married and 40% single life annuity if participant is single. The present value assumptions used in calculating the present value of accumulated benefits for the Retirement Plan were as follows: a discount rate of 5.20%; an expected retirement age of 65; cash balance interest crediting assumption of 5.98% for 2024 and 2025, and 3.10% thereafter; postretirement mortality using the Pri-2012 gender specific tables; generational mortality improvements from 2012 forward based on MP-2021; and the applicable lump sum interest and mortality rates set forth in IRC 417(e)(3) for the upcoming fiscal year.

Historically, PacifiCorp has adopted the Retirement Plan for the majority of its employees, other than employees subject to collective bargaining agreements that do not provide for coverage under the Retirement Plan. Through May 31, 2007, participants earned benefits at retirement payable for life based on length of service through May 31, 2007 and average pay in the 60 consecutive months of highest pay out of the 120 months prior to May 31, 2007. Pay for this purpose included base salary and annual incentive plan payments up to 10% of base salary, but was limited to the amounts specified in Internal Revenue Code Section 401(a)(17). Benefits were based on 1.3% of final average pay plus 0.65% of final average pay in excess of covered compensation (as defined in Internal Revenue Code Section 401(1)(5)(E)) multiplied by years of service.

The Retirement Plan was amended effective June 1, 2007 to change from a traditional final average pay formula as described above to a cash balance formula for non-union participants. Benefits under the final average pay formula were frozen as of May 31, 2007, and no future benefits will accrue under that formula for non-union participants. Under the cash balance formula, benefits are based on pay credits to each participant's account of 6.5% (5.0% for employees hired after June 30, 2006 and before January 1, 2008) of eligible compensation. In addition, through August 1, 2009, there was a pay credit of 4% of eligible compensation in excess of the Social Security Wage Base. Interest is also credited to each participant's account. Employees who were age 40 or older as of May 31, 2007 received certain additional transition pay credits for five years from the effective date of the Retirement Plan restatement.

Participants in the Retirement Plan are entitled to receive full benefits upon retirement on or after age 65. Such participants are also entitled to receive reduced benefits upon early retirement after age 55 with at least five years of service or when age plus years of service equals 75.

The Retirement Plan was closed to non-union employees hired after December 31, 2007 (which includes Mr. Hoogeveen). In 2008, non-union employee participants in the Retirement Plan were offered the option to continue to receive pay credits in the Retirement Plan or receive equivalent fixed contributions to the 401(k) Plan with any such election becoming effective January 1, 2009. Ms. Kobliha elected the equivalent fixed 401(k) contribution option and, therefore, no longer receives pay credits in the Retirement Plan. In 2017, the Retirement Plan was frozen for the remainder of the non-union employees who had participated (which includes Ms. Crane and Mr. Bird) with pay credits equivalent to those received in the Retirement Plan allocated into the 401(k) Plan. Ms. Crane, Mr. Bird, and Ms. Kobliha continue to receive interest credits in the Retirement Plan.

Nonqualified Deferred Compensation

The following table sets forth certain information regarding the nonqualified deferred compensation plan accounts held by each of PacifiCorp's NEOs as of December 31, 2023:

Name	Executive contributions in 2023[(1)(2)]	Registrant contributions in 2023	Aggregate earnings/(losses) in 2023	Aggregate withdrawals/ distributions	Aggregate balance as of 12/31/2023[(3)]
Cindy A. Crane	$ —	$ —	$ 407,990	$ (468,054)	$ 4,297,461
Stefan A. Bird	—	—	—	—	—
Gary W. Hoogeveen	253,626	—	646,887	(101,759)	4,405,856
Nikki L. Kobliha	247,882	—	129,088	—	1,182,515

(1) The executive contribution amount shown for Mr. Hoogeveen represents a deferral of $253,626 of his 2020 LTIP award. $180,130 of the deferred 2020 LTIP award is included in the 2023 total compensation reported for him in the Summary Compensation Table and is not additional compensation. The remaining LTIP award was earned prior to 2023.

(2) The executive contribution amount shown for Ms. Kobliha represents a deferral of $60,289 of her 2023 compensation and a deferral of $187,593 of her 2020 LTIP award. $74,183 of the deferred 2020 LTIP award is included in the 2023 total compensation reported for her in the Summary Compensation Table and is not additional compensation. The remaining LTIP award was earned prior to 2023.

(3) The aggregate balance as of December 31, 2023, shown for Mr. Hoogeveen and Ms. Kobliha includes $642,091 and $149,598, respectively, of compensation previously reported in the Summary Compensation Table.

Eligibility for PacifiCorp's DCP is restricted to select management and highly compensated employees. The plan provides tax benefits to eligible participants by allowing them to defer compensation on a pretax basis, thus reducing their current taxable income. Deferrals and any investment returns grow on a tax-deferred basis, thus participants pay no income tax until they receive distributions. The DCP permits participants to make a voluntary deferral of up to 50% of base salary and 100% of short-term incentive compensation awards. All deferrals are net of social security taxes. Amounts deferred under the DCP receive a rate of return based on the returns of any combination of various investment alternatives offered by the plan and selected by the participant. Gains or losses are calculated daily, and returns are posted to accounts based on participants' fund allocation elections. Participants can change their fund allocations as of the end of any day on which the market is open.

The DCP allows participants to maintain three accounts based upon when they want to receive payments: retirement account, in-service account and education account. Both the retirement and in-service accounts can be distributed as lump sums or in up to 10 annual installments, except in the case of the four DCP transition accounts that allow for a grandfathered payout based on the previous deferred compensation plan distribution elections of lump sum, 5, 10 or 15 annual installments. Effective December 31, 2006, no new money may be deferred into the DCP transition accounts. The education account is distributed in four annual installments. If a participant leaves employment prior to retirement (age 55), all amounts in the participant's account will be paid out in a lump sum as soon as administratively practicable. Participants are 100% vested in their deferrals and any investment gains or losses recorded in their accounts.

Participants in PacifiCorp's LTIP also have the option of deferring all or a part of those awards after the four-year mandatory deferral and vesting period. The provisions governing the deferral of LTIP awards are similar to those described for the DCP above.

Potential Payments Upon Termination

PacifiCorp's NEOs are not generally entitled to severance or enhanced benefits upon termination of employment or change in control. None of PacifiCorp's NEOs have a formal employment agreement or offer letter with termination provisions; therefore, payments upon termination are determined by the applicable plan documents, applicable Critical Personnel Agreements and PacifiCorp's general employment policies and practices as discussed below.

The following table sets forth the estimated increase in the present value of benefits pursuant to the termination scenarios indicated for PacifiCorp's NEOs. Payments or benefits that are not enhanced in form or amount upon the occurrence of a particular termination scenario, which include 401(k) and nonqualified deferred compensation account balances and those portions of long-term incentive payments that would have otherwise been paid, are not included herein. All estimated payments reflected in the table below assume termination on December 31, 2023 and are payable as lump sums unless otherwise noted.

Termination Scenario	Incentive [1]	Pension [2]
Cindy A. Crane		
Retirement, Voluntary and Involuntary With or Without Cause	$ —	$ 13,526
Death and Disability	—	13,526
Stefan A. Bird:		
Retirement, Voluntary and Involuntary With or Without Cause	—	16,930
Death and Disability	487,362	16,930
Gary W. Hoogeveen:		
Retirement, Voluntary and Involuntary With or Without Cause	—	n/a
Death and Disability	505,886	n/a
Nikki L. Kobliha:		
Retirement, Voluntary and Involuntary With or Without Cause	—	—
Death and Disability	134,288	—
Termination, For Good Reason or Without Cause	1,520,107	n/a

(1) Death and Disability amounts represent the unvested portion of each NEO's LTIP account, which becomes 100% vested under certain circumstances. For Ms. Kobliha Termination, For Good Reason or Without Cause amounts represent the unearned portion of amounts awarded under her Critical Personnel Agreement, which become 100% earned and payable under such circumstances where Termination For Good Reason occurs if the employee terminates employment in the event PacifiCorp or its subsidiaries engage in fraudulent or gross misconduct.

(2) Pension values represent the excess of the present value of benefits payable under each termination scenario over the amount already reflected in the Pension Benefits table.

Chief Executive Officer Pay Ratio

PacifiCorp's former CEO, Mr. Thon, received no direct compensation from PacifiCorp, and no amounts are reported for Mr. Thon in the Summary Compensation Table. Ms. Crane received direct compensation from PacifiCorp in her role as CEO beginning September 1, 2023. Accordingly, PacifiCorp has calculated the CEO pay ratio based upon annualization of Ms. Crane's compensation.

The following information about the relationship of the annualized total compensation of Ms. Crane to the annual total compensation of the individual identified as PacifiCorp's "median" employee is provided in accordance with Section 953(b) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 402(u) of Regulation S-K.

- The 2023 annualized total compensation of Ms. Crane was $2,198,393;
- The 2023 annual total compensation of the employee identified as PacifiCorp's median employee based on all employees other than Ms. Crane was $134,025; and
- The resulting ratio between the 2023 annualized total compensation of Ms. Crane to the 2023 annual total compensation of the identified median employee is 16.4-to-1.

The methodology and material assumptions, adjustments and estimates used to identify the median employee for this purpose were as follows:

- A determination date of December 31, 2023 was used for purposes of identifying the median employee at which time PacifiCorp's employee population consisted of approximately 5,000 individuals, all of whom were located in the United States.
- For purposes of measuring the compensation of employees to identify the median employee, rather than using annual total compensation, base salary and wages with overtime pay plus AIP for 2023 was used as the compensation measure.

- Employee compensation was annualized for any new hires in 2023 as if they were hired at the beginning of the fiscal year in identifying the median employee.
- To determine the annualized total compensation of Ms. Crane, the amount reported for Ms. Crane in the "Salary" column for 2023 in the Summary Compensation Table was annualized.

This pay ratio is a reasonable estimate calculated in a manner consistent with SEC rules based on payroll and employment records and the methodology described above. The SEC rules for identifying the median paid employee and calculating this pay ratio allow companies to apply various methodologies and assumptions. As a result, the pay ratio reported above may not be comparable to the pay ratio reported by other companies.

Director Compensation

PacifiCorp's directors do not receive additional compensation for their service as directors of PacifiCorp. Compensation information for Ms. Crane, Messrs. Thon, Bird, Hoogeveen, and Ms. Kobliha for their services as executive officers of PacifiCorp is described above.

Compensation Committee Interlocks and Insider Participation

Ms. Crane is PacifiCorp's Chair and CEO. None of PacifiCorp's executive officers serves as a member of the compensation committee of any company that has an executive officer serving as a member of PacifiCorp's Board of Directors. None of PacifiCorp's executive officers serves as a member of the board of directors of any company that has an executive officer serving as a member of PacifiCorp's compensation committee. See also PacifiCorp's Item 13 in this Annual Report on Form 10-K.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

BERKSHIRE HATHAWAY ENERGY, 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.

PACIFICORP

Beneficial Ownership

PacifiCorp is a consolidated subsidiary of BHE. PacifiCorp's common stock is indirectly owned by BHE, 666 Grand Avenue, Des Moines, Iowa 50309-2580. BHE is a consolidated subsidiary of Berkshire Hathaway that, as of January 31, 2024, owns 92% of BHE's common stock. The balance of BHE's common stock is privately held by a limited group of investors.

None of PacifiCorp's executive officers or directors owns shares of its preferred stock. The following table sets forth certain information regarding the beneficial ownership of BHE's common stock and the Class A and Class B shares of Berkshire Hathaway common stock held by each of PacifiCorp's directors, executive officers and all of its directors and executive officers as a group as of January 31, 2024:

	BHE		Berkshire Hathaway			
	Common Stock		Class A Common Stock		Class B Common Stock	
Beneficial Owner	Number of Shares Beneficially Owned(1)	Percentage of Class(1)	Number of Shares Beneficially Owned(1)	Percentage of Class(1)	Number of Shares Beneficially Owned(1)	Percentage of Class(1)
Cindy A. Crane	—	—	—	—	—	—
Calvin D. Haack	—	—	—	—	—	—
Natalie L. Hocken	—	—	—	—	—	—
Nikki L. Kobliha	—	—	—	—	—	—
Gary W. Hoogeveen	—	—	—	—	511	*
All executive officers and directors as a group (5 persons)	—	—	—	—	511	*

* Indicates beneficial ownership of less than one percent of all outstanding shares.

(1) Includes shares of which the listed beneficial owner is deemed to have the right to acquire beneficial ownership under Rule 13d-3(d) under the Securities Exchange Act, including, among other things, shares which the listed beneficial owner has the right to acquire within 60 days.

Item 13. Certain Relationships and Related Transactions, and Director Independence

BERKSHIRE HATHAWAY ENERGY, 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.

PACIFICORP

Certain Relationships and Related Transactions

The Berkshire Hathaway Inc. Code of Business Conduct and Ethics and the BHE Code of Business Conduct, or the Codes, which apply to all of PacifiCorp's directors, officers and employees and those of its subsidiaries, generally govern the review, approval or ratification of any related-person transaction. A related-person transaction is one in which PacifiCorp or any of its subsidiaries participate and in which one or more of PacifiCorp's directors, executive officers, holders of more than five percent of its voting securities or any of such persons' immediate family members have a direct or indirect material interest.

Under the Codes, all of PacifiCorp's directors and executive officers (including those of its subsidiaries) must disclose to PacifiCorp's legal department any material transaction or relationship that reasonably could be expected to give rise to a conflict with its interests. No action may be taken with respect to such transaction or relationship until approved by the legal department. For PacifiCorp's chief executive officer and chief financial officer, prior approval for any such transaction or relationship must be given by Berkshire Hathaway's audit committee. In addition, prior legal department approval must be obtained before a director or executive officer can accept employment, offices or board positions in other for-profit businesses, or engage in his or her own business that raises a potential conflict or appearance of conflict with PacifiCorp's interests.

Under an intercompany administrative services agreement PacifiCorp has entered into with BHE and its other subsidiaries, the costs of certain administrative services provided by BHE to PacifiCorp or by PacifiCorp to BHE, or shared with BHE and other subsidiaries, are directly charged or allocated to the entity receiving such services. This agreement has been filed with the regulatory commissions in the states where PacifiCorp serves retail customers. PacifiCorp also provides an annual report of all transactions with its affiliates to its state regulatory commissions, who have the authority to refuse recovery in rates for payments PacifiCorp makes to its affiliates deemed to have the effect of subsidizing the separate business activities of BHE or its other subsidiaries.

Refer to Note 21 of the Notes to the Consolidated Financial Statements of PacifiCorp in Item 8 of this Form 10-K for additional information regarding related party transactions.

Director Independence

Because PacifiCorp's common stock is indirectly, wholly owned by BHE and its Board of Directors consists of BHE and PacifiCorp employees, PacifiCorp is not required to have independent directors or audit, nominating or compensation committees consisting of independent directors.

Based on the standards of the New York Stock Exchange LLC, on which the common stock of PacifiCorp's ultimate parent company, Berkshire Hathaway, is listed, PacifiCorp's Board of Directors has determined that none of its directors are considered independent because of their employment by BHE or PacifiCorp.

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
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
2022								
Audit fees(2)	$ 12.6	$ 1.7	$ 1.3	$ 1.2	$ 1.0	$ 0.9	$ 1.7	$ 1.3
Audit-related fees(3)	0.8	—	—	—	—	—	0.2	0.1
Tax fees(4)	—	—	—	—	—	—	—	—
Other	0.6	—	—	—	—	—	—	—
Total	$ 14.0	$ 1.7	$ 1.3	$ 1.2	$ 1.0	$ 0.9	$ 1.9	$ 1.4

(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. Under the policy, requests to provide services that require specific approval by the audit committee will be submitted to the audit committee by both the Registrants' independent auditor and BHE's Chief Financial Officer. All requests for services to be provided by the independent auditor that do not require specific approval by the audit committee will be submitted to BHE's Chief Financial Officer and must include a detailed description of the services to be rendered. BHE's Chief Financial Officer will determine whether such services are included within the list of services that have received the general pre-approval of the audit committee. The audit committee will be informed on a timely basis of any such services rendered by the independent auditor.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) Financial Statements and Schedules

(1) Financial Statements

(2) Financial Statement Schedules

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.

(b) Exhibits

Item 16. Form 10-K Summary

None.

Schedule I

BERKSHIRE HATHAWAY ENERGY COMPANY
PARENT COMPANY ONLY
CONDENSED BALANCE SHEETS
(Amounts in millions)

	As of December 31,	
	2023	**2022**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 166	$ 32
Accounts receivable	—	4
Accounts receivable - affiliate	861	263
Notes receivable - affiliate	19	10
Income tax receivable	44	28
Other current assets	15	12
Total current assets	1,105	349
Investments in subsidiaries	61,032	59,944
Other investments	248	205
Goodwill	1,221	1,221
Other assets	1,291	1,152
Total assets	$ 64,897	$ 62,871
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable and other current liabilities	$ 613	$ 429
Notes payable - affiliate	202	287
Short-term debt	1,935	245
Current portion of BHE senior debt	—	900
Total current liabilities	2,750	1,861
BHE senior debt	13,101	13,096
BHE junior subordinated debentures	100	100
Notes payable - affiliate	—	477
Other long-term liabilities	512	505
Total liabilities	16,463	16,039
Equity:		
BHE shareholders' equity:		
Preferred stock - 100 shares authorized, $0.01 par value, 0 and 1 shares issued and outstanding	—	850
Common stock - 115 shares authorized, no par value, 76 shares issued and outstanding	—	—
Additional paid-in capital	5,573	6,298
Retained earnings	44,765	41,833
Accumulated other comprehensive loss, net	(1,904)	(2,149)
Total BHE shareholders' equity	48,434	46,832
Total equity	48,434	46,832
Total liabilities and equity	$ 64,897	$ 62,871

The accompanying notes are an integral part of this financial statement schedule.

Schedule I

BERKSHIRE HATHAWAY ENERGY COMPANY
PARENT COMPANY ONLY
CONDENSED STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2023	2022	2021
Operating expenses:			
General and administration	$ 77	$ 31	$ 83
Depreciation and amortization	7	8	6
Total operating expenses	84	39	89
Operating loss	(84)	(39)	(89)
Other income (expense):			
Interest expense	(702)	(629)	(580)
Other, net	49	(45)	1,846
Total other income (expense)	(653)	(674)	1,266
(Loss) income before income tax expense (benefit) and equity income (loss)	(737)	(713)	1,177
Income tax expense (benefit)	(233)	(259)	194
Equity income (loss)	3,524	3,175	4,807
Net income	3,020	2,721	5,790
Net income attributable to noncontrolling interest	—	—	—
Net income attributable to BHE shareholders	3,020	2,721	5,790
Preferred dividends	34	46	121
Earnings on common shares	$ 2,986	$ 2,675	$ 5,669

The accompanying notes are an integral part of this financial statement schedule.

Schedule I

BERKSHIRE HATHAWAY ENERGY COMPANY
PARENT COMPANY ONLY
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME
(Amounts in millions)

	Years Ended December 31,		
	2023	**2022**	**2021**
Net income	$ 3,020	$ 2,721	$ 5,790
Other comprehensive income (loss), net of tax	246	(809)	212
Comprehensive income	3,266	1,912	6,002
Comprehensive income attributable to noncontrolling interests	—	—	—
Comprehensive income attributable to BHE shareholders	$ 3,266	$ 1,912	$ 6,002

The accompanying notes are an integral part of this financial statement schedule.

Schedule I

BERKSHIRE HATHAWAY ENERGY COMPANY
PARENT COMPANY ONLY
CONDENSED STATEMENTS OF CASH FLOWS
(In millions)

	Years Ended December 31,		
	2023	2022	2021
Cash flows from operating activities	$ 5,824	$ 1,252	$ 1,819
Cash flows from investing activities:			
Investments in subsidiaries	(4,995)	(1,085)	(1,206)
Purchases of marketable securities	(39)	(20)	(29)
Proceeds from sales of marketable securities	35	11	28
Proceeds from other investments	—	—	1,290
Notes receivable from affiliate, net	(571)	390	200
Other, net	(18)	(44)	(20)
Net cash flows from investing activities	(5,588)	(748)	263
Cash flows from financing activities:			
Preferred stock redemptions	(850)	(800)	(2,100)
Preferred dividends	(38)	(50)	(132)
Common stock purchases	—	(870)	—
Proceeds from BHE senior debt	—	986	—
Repayments of BHE senior debt	(900)	—	(450)
Net proceeds from (repayments of) short-term debt	1,690	245	—
Other, net	(4)	(1)	(5)
Net cash flows from financing activities	(102)	(490)	(2,687)
Net change in cash and cash equivalents	134	14	(605)
Cash and cash equivalents at beginning of year	32	18	623
Cash and cash equivalents at end of year	$ 166	$ 32	$ 18

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, 2023, 2022 and 2021 were $6.8 billion, $1.9 billion and $2.4 billion, respectively. In January and February 2024, BHE received cash dividends from its subsidiaries totaling $691 million.

Guarantees and commitments - BHE has issued guarantees and letters of credit in respect of subsidiaries, equity method investments and other related parties aggregating $2.6 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,	
	2023	2022
ASSETS		
Current assets:		
Receivables from affiliates	$ 1	$ 1
Investments in and advances to subsidiaries	10,925	10,959
Total assets	$ 10,926	$ 10,960
LIABILITIES AND MEMBER'S EQUITY		
Current liabilities:		
Interest accrued and other current liabilities	$ 5	$ 5
Payable to affiliate	48	36
Long-term debt	240	240
Total liabilities	293	281
Member's equity:		
Paid-in capital	1,679	1,679
Retained earnings	8,954	9,000
Total member's equity	10,633	10,679
Total liabilities and member's equity	$ 10,926	$ 10,960

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,		
	2023	2022	2021
Other income (expense):			
Interest expense	$ (17)	$ (17)	$ (16)
Loss before income taxes	(17)	(17)	(16)
Income tax expense (benefit)	(5)	(5)	(5)
Equity in undistributed earnings of subsidiaries	992	959	894
Net income	$ 980	$ 947	$ 883

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,		
	2023	2022	2021
Net cash flows from operating activities	$ (12)	$ (12)	$ (12)
Net cash flows from investing activities:			
Dividends from subsidiary	1,025	69	—
Net cash flows from investing activities	1,025	69	—
Net cash flows from financing activities:			
Distributions to member	(1,025)	(69)	—
Net change in amounts payable to subsidiary	12	12	12
Net cash flows from financing activities	(1,013)	(57)	12
Net change in cash and cash equivalents	—	—	—
Cash and cash equivalents at beginning of year	—	—	—
Cash and cash equivalents at end of year	$ —	$ —	$ —

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, 2023, 2022 and 2021 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, 2023, 2022 and 2021.

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 $1,037 million, $81 million and $12 million in 2023, 2022 and 2021, respectively, on behalf of MidAmerican Funding.

Distributions to Parent - In 2023 and 2022, MidAmerican Funding declared and paid, via MHC, cash dividends of $1,025 million and $69 million, respectively. In February 2024, MidAmerican Funding declared and paid, via MHC, a cash dividend of $425 million.

See the notes to the consolidated MidAmerican Funding financial statements in Part II, Item 8 for other disclosures.

EXHIBIT INDEX

Exhibit No.	Description
BERKSHIRE HATHAWAY ENERGY	
3.1	Second Amended and Restated Articles of Incorporation of MidAmerican Energy Holdings Company effective March 2, 2006 (incorporated by reference to Exhibit 3.1 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2005).
3.2	Articles of Amendment to the Second Amended and Restated Articles of Incorporation of MidAmerican Energy Holdings Company effective April 30, 2014 (incorporated by reference to Exhibit 3.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2014).
3.3	Third Amended and Restated Articles of Incorporation of Berkshire Hathaway Energy Company, effective as of October 22, 2020 (incorporated by reference to Exhibit 3.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated November 2, 2020).
3.4	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).
4.1	Shareholders Agreement, dated as of March 14, 2000 (incorporated by reference to Exhibit 4.19 to the Berkshire Hathaway Energy Company Registration Statement No. 333-101699 dated December 6, 2002).
4.2	Amendment No. 1 to Shareholders Agreement, dated December 7, 2005 (incorporated by reference to Exhibit 4.17 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2005).
4.3	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).
4.4	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).
4.5	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).
4.6	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).
4.7	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).
4.8	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).
4.9	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).
4.10	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).

Exhibit No.	Description
4.11	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).
4.12	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).
4.13	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).
4.14	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).
4.15	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).
4.16	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).
4.17	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).
4.18	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).
4.19	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).
4.20	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).
4.21	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).
4.22	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).
4.23	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).
4.24	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).

Exhibit No.	Description
4.25	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).
4.26	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.
4.27	£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).
4.28	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).
4.29	£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).
4.30	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).
4.31	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).
4.32	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).
4.33	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).
4.34	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).
4.35	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).
4.36	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).
4.37	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).
4.38	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).

Exhibit No.	Description
4.39	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).
4.40	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).
4.41	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.
4.42	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).
4.43	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).
4.44	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).
4.45	Tenth Supplemental Indenture, dated May 21, 2008, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.102 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.46	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).
4.47	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).
4.48	Seventeenth Supplemental Indenture, dated May 22, 2013, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.105 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.49	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).
4.50	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).
4.51	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).
4.52	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).

Exhibit No.	Description
4.53	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).
4.54	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).
4.55	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).
4.56	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).
4.57	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).
4.58	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).
4.59	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).
10.1	First Amendment to the $3,500,000,000 Third Amended and Restated Credit Agreement, dated as of June 30, 2023, 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 10.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2023).
10.2	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).
10.3	Amended and Restated Credit Agreement, dated as of January 24, 2020, among AltaLink Investments, L.P., as borrower, AltaLink Investment Management Ltd., as general partner, Royal Bank of Canada, as administrative agent, and Lenders (incorporated by reference to Exhibit 10.3 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2019).
10.4	Third Amending Agreement to the Amended and Restated Credit Agreement, dated as of December 15, 2021, among AltaLink Investments, L.P., as borrower, AltaLink Investment Management Ltd., as general partner, Royal Bank of Canada, as administrative agent, and Lenders (incorporated by reference to Exhibit 10.4 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2021).
10.5	Fourth Amending Agreement to the Amended and Restated Credit Agreement, dated as of September 5, 2023, among AltaLink Investments, L.P., as borrower, AltaLink Investment Management Ltd., as general partner, Royal Bank of Canada, as administrative agent, and Lenders (incorporated by reference Exhibit 10.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2023).

Exhibit No.	Description
10.6	Fifth Amending Agreement to the Amended and Restated Credit Agreement, dated as of September 28, 2023, among AltaLink Investments, L.P., as borrower, AltaLink Investment Management Ltd., as general partner, Royal Bank of Canada, as administrative agent, and Lenders (incorporated by reference Exhibit 10.2 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2023).
10.7	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).
10.8	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).
10.9	Credit Agreement, dated as of April 27, 2020, among AltaLink Investments, L.P., as borrower, AltaLink Investment Management Ltd., as general partner, Royal Bank of Canada, as administrative agent, and Lenders (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, 2020).
10.10	First Amending Agreement to the Credit Agreement, dated April 27, 2021, among AltaLink Investments, L.P., as borrower, AltaLink Investment Management Ltd., as general partner, Royal Bank of Canada, as administrative agent, and Lenders (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, 2023).
10.11	Third Amending Agreement to the Credit Agreement, dated April 27, 2023, among AltaLink Investments, L.P., as borrower, AltaLink Investment Management Ltd., as general partner, Royal Bank of Canada, as administrative agent, and Lenders (incorporated by reference to Exhibit 10.3 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2023).
10.12	Credit Agreement, dated as of December 22, 2023, among BHE Canada Holdings Corporation, as borrower, Bank of Montreal, as administrative agent, and Lenders (redacted).
10.13	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).
10.14	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).
14.1	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).
21.1	Subsidiaries of the Registrant.
23.1	Consent of Deloitte & Touche LLP.
24.1	Power of Attorney.
31.1	Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

PACIFICORP

3.5	Third Restated Articles of Incorporation of PacifiCorp (incorporated by reference to Exhibit (3)a to the PacifiCorp Annual Report on Form 10-K for the year ended December 31, 1996).
3.6	Bylaws of PacifiCorp, as amended December 15, 2023.
10.15*	Summary of Key Terms of Compensation Arrangements with PacifiCorp's Named Executive Officers and Directors.
10.16*	PacifiCorp Executive Voluntary Deferred Compensation Plan (incorporated by reference to Exhibit 10.3 to the PacifiCorp Annual Report on Form 10-K for the year ended December 31, 2007).
10.17*	Supplemental Executive Retirement Plan (incorporated by reference to Exhibit 10.7 to the PacifiCorp Annual Report on Form 10-K for the year ended March 31, 2005).

Exhibit No.	Description
10.18*	Amendment No. 10 to PacifiCorp Supplemental Executive Retirement Plan dated June 2, 2006 (incorporated by reference to Exhibit 10.5 to the PacifiCorp Quarterly Report on Form 10-Q for the quarter ended June 30, 2006).
10.19*	Amendment No. 11 to PacifiCorp Supplemental Executive Retirement Plan dated June 2, 2006 (incorporated by reference to Exhibit 10.6 to the PacifiCorp Quarterly Report on Form 10-Q for the quarter ended June 30, 2006).
10.20*	Amendment No. 1 to the PacifiCorp Executive Voluntary Deferred Compensation Plan dated October 28, 2008 (incorporated by reference to Exhibit 10.10 to the PacifiCorp Annual Report on Form 10-K for the year ended December 31, 2009).
10.21*	Amendment No. 2 to the PacifiCorp Executive Voluntary Deferred Compensation Plan dated October 16, 2012 (incorporated by reference to Exhibit 10.11 to the PacifiCorp Annual Report on Form 10-K for the year ended December 31, 2012).
10.22*	PacifiCorp Long Term Incentive Partnership Plan effective January 1, 2014 and Restated Effective December 1, 2019 (incorporated by reference to Exhibit 10.15 to the PacifiCorp Annual Report on Form 10-K for the year ended December 31, 2019).
10.23*	PacifiCorp's Chief Executive Officer Offer Letter, dated August 17, 2023.
10.24*	PacifiCorp's Critical Personnel Agreement, dated December 1, 2023.
14.2	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).
23.2	Consent of Deloitte & Touche LLP.
31.3	Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.4	Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.3	Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.4	Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

Exhibit No.	**Description**

BERKSHIRE HATHAWAY ENERGY AND PACIFICORP

4.60 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:

Exhibit Number	PacifiCorp File Type	File Date
(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
(4)a	10-Q	Quarter ended June 30, 1994
(4)b	10-K	Year ended December 31, 1994
(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

10.25 First Amendment to the $2,000,000,000 Third Amended and Restated Credit Agreement, dated as of June 30, 2023, among PacifiCorp, as Borrower, the Banks, Financial Institutions and Other Institutional Lenders, as Initial Lenders, JP Morgan 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, 2023).

Exhibit No.	Description
10.26	$900,000,000 Delayed Draw Term Loan Agreement, dated as of December 21, 2023, 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 10.1 to the PacifiCorp Current Report on Form 8-K filed December 21, 2023).
95	Mine Safety Disclosures Required by the Dodd-Frank Wall Street Reform and Consumer Protection Act.

MIDAMERICAN ENERGY

3.7	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).
3.8	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).
14.3	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).
23.3	Consent of Deloitte & Touche LLP.
31.5	Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.6	Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.5	Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.6	Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

MIDAMERICAN FUNDING

3.9	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).
3.10	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).
3.11	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).
14.4	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).
31.7	Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.8	Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.7	Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.8	Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

BERKSHIRE HATHAWAY ENERGY, MIDAMERICAN ENERGY AND MIDAMERICAN FUNDING

4.61	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).
4.62	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).
4.63	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).

Exhibit No.	Description
4.64	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).
4.65	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).
4.66	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).
4.67	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).
4.68	Specimen of 3.70% First Mortgage Bonds due 2023 (incorporated by reference to Exhibit 4.3 to the MidAmerican Energy Company Current Report on Form 8-K dated September 19, 2013).
4.69	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).
4.70	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).
4.71	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).
4.72	Specimen of 3.50% First Mortgage Bonds due 2024 (incorporated by reference to Exhibit 4.4 to the MidAmerican Energy Company Current Report on Form 8-K dated April 3, 2014).
4.73	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).
4.74	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).
4.75	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).
4.76	Specimen of 3.50% First Mortgage Bonds due 2024 (incorporated by reference to Exhibit 4.3 to the MidAmerican Energy Company Current Report on Form 8-K dated October 15, 2015).
4.77	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).
4.78	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).
4.79	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).
4.80	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).
4.81	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).

Exhibit No.	Description
4.82	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).
4.83	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).
4.84	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).
4.85	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).
4.86	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).
4.87	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).
4.88	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).
4.89	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).
4.90	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).
4.91	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).
4.92	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).
4.93	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).
4.94	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).
4.95	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).
4.96	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).
4.97	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).
4.98	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).
4.99	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).

Exhibit No.	Description
4.100	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).
4.101	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).
10.27	First Amendment to the $1,500,000,000 Third Amended and Restated Credit Agreement, dated as of June 30, 2023, 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, 2023).

BERKSHIRE HATHAWAY ENERGY AND MIDAMERICAN FUNDING

4.102	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).

NEVADA POWER

3.12	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).
3.13	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).
4.103	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).
4.104	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).
10.28	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).
10.29	$300,000,000 Delayed Draw Term Loan Agreement, dated as of January 14, 2022, among Nevada Power Company, as Borrower, the Banks, Financial Institutions and Other Institutional Lenders, as Initial Lenders, U.S. Bank National Association, as Administrative Agent and U.S. Bank National Association and Sumitomo Mitsui Banking Corporation, as Joint Lead Arrangers and Joint Bookrunners (incorporated by reference to Exhibit 10.23 to the Nevada Power Company Annual Report on Form 10-K for the year ended December 31, 2021).
14.5	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).
23.4	Consent of Deloitte & Touche LLP.
31.9	Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.10	Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.9	Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.10	Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

Exhibit No.	Description
BERKSHIRE HATHAWAY ENERGY AND NEVADA POWER	
4.105	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).
4.106	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).
4.107	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 Form 10-Q for the quarter ended March 31, 2006).
4.108	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).
4.109	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).
4.110	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).
4.111	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).
4.112	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).
4.113	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).
4.114	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).
4.115	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).
4.116	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).
10.30	First Amendment to the $600,000,000 Fifth Amended and Restated Credit Agreement, dated as of June 30, 2023, 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, 2023).
SIERRA PACIFIC	
3.14	Restated Articles of Incorporation of Sierra Pacific Power Company, dated October 25, 2006 (incorporated by reference to Exhibit 3.1 to the Sierra Pacific Power Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2006).
3.15	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).
3.16	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).

Exhibit No.	Description
4.117	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).
4.118	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).
4.119	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).
10.31	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).
10.32	$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).
14.6	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).
31.11	Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.12	Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.11	Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.12	Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

BERKSHIRE HATHAWAY ENERGY AND SIERRA PACIFIC

4.120	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).
4.121	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).
4.122	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 4.2 to the Sierra Pacific Power Company Current Report on Form 8-K dated June 3, 2022).
4.123	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).
4.124	Officer's Certificate establishing the terms of Sierra Pacific Power Company's 3.375% General and Refunding Mortgage Notes, Series T, due 2023 (incorporated by reference to Exhibit 4.1 to the Sierra Pacific Power Company Current Report on Form 8-K dated August 14, 2013).
4.125	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).
4.126	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).

Exhibit No.	Description
4.127	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).
4.128	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).
4.129	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).
10.33	First Amendment to the $400,000,000 Fifth Amended and Restated Credit Agreement, dated as of June 30, 2023, 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, 2023).

EASTERN ENERGY GAS

3.17	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).
3.18	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).
3.19	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).
10.34	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).
10.35	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).
10.36	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).
10.37	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.
23.5	Consent of Deloitte & Touche LLP.
31.13	Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.14	Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.13	Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.14	Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

BERKSHIRE HATHAWAY ENERGY AND EASTERN ENERGY GAS

2.1	Purchase and Sale Agreement, dated as of July 9, 2023, by and between Dominion Energy, Inc., DECP Holdings Inc., Eastern MLP Holding Company II, LLC and Berkshire Hathaway Energy Company (incorporated by reference to Exhibit 2.1 to the Berkshire Hathaway Energy Company and Eastern Energy Gas Holdings, LLC Current Report on Form 8-K dated September 1, 2023).
4.130	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).
4.131	Second 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 3.55% Senior Notes due 2023 (incorporated by reference to Exhibit 4.3, Form S-4, File No. 333-195066 dated April 4, 2014).

Exhibit No.	Description
4.132	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).
4.133	Fifth 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 3.60% Senior Notes due 2024 (incorporated by reference to Exhibit 4.3 to the Eastern Energy Gas Holdings, LLC Current Report on Form 8-K dated December 8, 2014).
4.134	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).
4.135	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 Form 10-Q for the quarter ended June 30, 2016).
4.136	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 Form 10-Q for the quarter ended June 30, 2016).
4.137	Tenth 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 2.875% Senior Notes due 2023 (incorporated by reference to Exhibit 4.1.c to the Eastern Energy Gas Holdings, LLC Form 10-Q for the quarter ended June 30, 2016).
4.138	Eleventh Supplemental Indenture, dated June 1, 2018, by and between Dominion Energy Gas Holdings, LLC and Deutsche Bank Trust Company Americas, Trustee, relating to the Floating Rate Senior Notes due 2021 (incorporated by reference to Exhibit 4.2 to the Eastern Energy Gas Holdings, LLC Current Report on Form 8-K dated June 19, 2018).
4.139	Twelfth Supplemental Indenture, dated November 1, 2019, by and between Dominion Energy Gas Holdings, LLC and Deutsche Bank Trust Company Americas, Trustee, relating to the 2.50% Senior Notes due 2024 (incorporated by reference to Exhibit 4.2 to the Eastern Energy Gas Holdings, LLC Current Report on Form 8-K dated November 21, 2019).
4.140	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).
4.141	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).
4.142	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).
4.143	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).

EASTERN GAS TRANSMISSION AND STORAGE

3.20	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).
3.21	Bylaws of Dominion Energy Transmission, Inc. (incorporated by reference to Exhibit 3.2, Form S-4, File No. 333-266049 dated July 25, 2022).
10.38	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).

Exhibit No.	Description
10.39	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).
31.15	Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.16	Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.15	Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.16	Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

BERKSHIRE HATHAWAY ENERGY AND EASTERN GAS TRANSMISSION AND STORAGE

4.144	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 Berkshire Hathaway Energy Company and Eastern Energy Gas Holdings, LLC combined Quarterly Report on Form 10-Q for the quarter ended June 30, 2021).
4.145	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 Berkshire Hathaway Energy Company and Eastern Energy Gas Holdings, LLC combined Quarterly Report on Form 10-Q for the quarter ended June 30, 2021).
4.146	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 Berkshire Hathaway Energy Company and Eastern Energy Gas Holdings, LLC combined Quarterly Report on Form 10-Q for the quarter ended June 30, 2021).
4.147	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 Berkshire Hathaway Energy Company and Eastern Energy Gas Holdings, LLC combined Quarterly Report on Form 10-Q for the quarter ended June 30, 2021).
4.148	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 Berkshire Hathaway Energy Company and Eastern Energy Gas Holdings, LLC combined Quarterly Report on Form 10-Q for the quarter ended June 30, 2021).
4.149	Fifth 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 3.600% Senior Notes due 2024 (incorporated by reference to Exhibit 4.11 to the Berkshire Hathaway Energy Company and Eastern Energy Gas Holdings, LLC combined Quarterly Report on Form 10-Q for the quarter ended June 30, 2021).

ALL REGISTRANTS

101	The following financial information from each respective Registrant's Annual Report on Form 10-K for the year ended December 31, 2023 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 23rd day of February 2024.

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
/s/ Scott W. Thon* Scott W. Thon	Director, President and Chief Executive Officer (principal executive officer)	February 23, 2024
/s/ Calvin D. Haack* Calvin D. Haack	Senior Vice President and Chief Financial Officer (principal financial and accounting officer)	February 23, 2024
/s/ Gregory E. Abel* Gregory E. Abel	Chair of the Board of Directors	February 23, 2024
/s/ Warren E. Buffett* Warren E. Buffett	Director	February 23, 2024
/s/ Marc D. Hamburg* Marc D. Hamburg	Director	February 23, 2024
*By: /s/ Natalie L. Hocken Natalie L. Hocken	Attorney-in-Fact	February 23, 2024

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 23rd day of February 2024.

PACIFICORP

/s/ Nikki L. Kobliha

Nikki L. Kobliha
Director, Vice President, Chief Financial Officer and Treasurer
(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.

Signature	Title	Date
/s/ Cindy A. Crane Cindy A. Crane	Chair of the Board of Directors and Chief Executive Officer (principal executive officer)	February 23, 2024
/s/ Nikki L. Kobliha Nikki L. Kobliha	Director, Vice President, Chief Financial Officer and Treasurer (principal financial and accounting officer)	February 23, 2024
/s/ Calvin D. Haack Calvin D. Haack	Director	February 23, 2024
/s/ Natalie L. Hocken Natalie L. Hocken	Director	February 23, 2024
/s/ Gary W. Hoogeveen Gary W. Hoogeveen	Director	February 23, 2024

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 23rd day of February 2024.

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:

Signature	Title	Date
/s/ Kelcey A. Brown Kelcey A. Brown	Director, President and Chief Executive Officer (principal executive officer)	February 23, 2024
/s/ Blake M. Groen Blake M. Groen	Director, Vice President and Chief Financial Officer (principal financial and accounting officer)	February 23, 2024

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 23rd day of February 2024.

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:

Signature	Title	Date
/s/ Kelcey A. Brown Kelcey A. Brown	Manager and President (principal executive officer)	February 23, 2024
/s/ Blake M. Groen Blake M. Groen	Vice President and Controller (principal financial and accounting officer)	February 23, 2024
/s/ Daniel S. Fick Daniel S. Fick	Manager	February 23, 2024
/s/ Calvin D. Haack Calvin D. Haack	Manager	February 23, 2024
/s/ Natalie L. Hocken Natalie L. Hocken	Manager	February 23, 2024

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 23rd day of February 2024.

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:

Signature	Title	Date
/s/ Douglas A. Cannon Douglas A. Cannon	Director, President and Chief Executive Officer (principal executive officer)	February 23, 2024
/s/ Michael J. Behrens Michael J. Behrens	Director, Vice President and Chief Financial Officer (principal financial and accounting officer)	February 23, 2024
/s/ Brandon M. Barkhuff Brandon M. Barkhuff	Director	February 23, 2024
/s/ Jennifer L. Oswald Jennifer L. Oswald	Director	February 23, 2024
/s/ Anthony F. Sanchez, III Anthony F. Sanchez, III	Director	February 23, 2024

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 23rd day of February 2024.

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:

Signature	Title	Date
/s/ Douglas A. Cannon Douglas A. Cannon	Director, President and Chief Executive Officer (principal executive officer)	February 23, 2024
/s/ Michael J. Behrens Michael J. Behrens	Vice President and Chief Financial Officer (principal financial and accounting officer)	February 23, 2024
/s/ Brandon M. Barkhuff Brandon M. Barkhuff	Director	February 23, 2024
/s/ Jesse E. Murray Jesse E. Murray	Director	February 23, 2024
/s/ Jennifer L. Oswald Jennifer L. Oswald	Director	February 23, 2024
/s/ Anthony F. Sanchez, III Anthony F. Sanchez, III	Director	February 23, 2024

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 23rd day of February 2024.

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:

Signature	Title	Date
/s/ Paul E. Ruppert Paul E. Ruppert	President and Chief Executive Officer (principal executive officer)	February 23, 2024
/s/ Scott C. Miller Scott C. Miller	Vice President, Chief Financial Officer and Treasurer (principal financial and accounting officer)	February 23, 2024
/s/ Mark A. Hewett Mark A. Hewett	Manager	February 23, 2024
/s/ Calvin D. Haack Calvin D. Haack	Manager	February 23, 2024
/s/ Natalie L. Hocken Natalie L. Hocken	Manager	February 23, 2024

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 23rd day of February 2024.

EASTERN GAS TRANSMISSION AND STORAGE, INC.

/s/ Paul E. Ruppert

Paul E. Ruppert
President and Chair of the Board of Directors
(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:

Signature	Title	Date
/s/ Paul E. Ruppert Paul E. Ruppert	President and Chair of the Board of Directors (principal executive officer)	February 23, 2024
/s/ Scott C. Miller Scott C. Miller	Vice President, Chief Financial Officer, Treasurer and Director (principal financial and accounting officer)	February 23, 2024
/s/ Anne E. Bomar Anne E. Bomar	Senior Vice President, General Counsel and Director	February 23, 2024

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.