BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

In the Matter of the Application of PACIFICORP (U-901-E), for an Order Authorizing a General Rate Increase Effective January 1, 2023.	Application No. 22-05-___ (Filed May 5, 2022)

APPLICATION OF PACIFICORP (U-901-E) FOR AN ORDER AUTHORIZING A GENERAL RATE INCREASE

Carla Scarsella
Ajay Kumar
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, OR 97232
Telephone: 503-813-6338
Email: carla.scarsella@pacificorp.com
ajay.kumar@pacificorp.com

DOWNEY BRAND, LLP
Michael B. Day
Megan Somogyi
455 Market Street, Suite 1500
San Francisco, California 94105
Telephone: (415) 848-4808
E-mail: mday@downeybrand.com
msomogyi@downeybrand.com

Date: May 5, 2022

Attorneys for PacifiCorp

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

In the Matter of the Application of PACIFICORP (U-901-E), for an Order Authorizing a General Rate Increase Effective January 1, 2023.	Application No. 22-05-____ (Filed May 5, 2022)

APPLICATION OF PACIFICORP (U-901-E) FOR AN ORDER AUTHORIZING A GENERAL RATE INCREASE

Pursuant to Articles 2 and 3 of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure (Rules) and Sections 451, 454, 491, 701, 728, and 729 of the California Public Utilities Code (Cal. Pub. Util. Code), PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company), respectfully submits this application requesting approval to increase its rates for electric service in California beginning January 1, 2023 (Application). As described below, PacifiCorp proposes an increase of approximately $27.9 million, or a 25.7 percent net increase, to its base electric rates in California. The revised rates will ensure PacifiCorp maintains financial integrity while the Company makes the necessary capital investments to transition to a cleaner energy future and continue its investment in wildfire mitigation and vegetation management.

I. BACKGROUND

PacifiCorp is a multi-jurisdictional utility providing retail electric service to customers in California, Idaho, Oregon, Utah, Washington, and Wyoming. In northern California, PacifiCorp serves approximately 47,800 customers spread over more than 11,000 square miles in portions of Del Norte, Modoc, Shasta, and Siskiyou counties.

As described in the testimony of Mr. Matthew McVee, PacifiCorp is filing its first general rate case since 2018 (2019 GRC or 2019 Rate Case).[1] The Company is continuing its transition to a non-emitting energy resource mix while providing safe, reliable, and affordable electric service to its customers, which has been driven by public policy, emerging and maturing technologies, and new levels of customer engagement. Even though it has and continues to make a concerted effort to manage its controllable costs, since its 2019 Rate Case, the Company is facing increasing costs related to wildfire mitigation and vegetation management. PacifiCorp has also continued its efforts to transition to a non-emitting energy resource mix. This work, coupled with the investment required to protect its system and customers from the increasing wildfire threat and increasing costs of vegetation management, will help position the Company to continue to respond proactively and ensure delivery of safe, reliable, affordable electric service to its customers

II. SUMMARY OF APPLICATION

A. Revenue Requirement and Rate Design

As a regulated utility, PacifiCorp has a duty and an obligation to provide safe, adequate, and reliable service to customers in its California service territory while balancing costs, risks, and state energy policy objectives. PacifiCorp's proposed rate increase is due primarily to several factors: namely, the increased operating expenses and Company investments in wildfire mitigation and vegetation management. PacifiCorp understands the impact that a rate increase has on its customers, and, in order to mitigate future increases related to wildfire mitigation

[1] *In the Matter of the Application of PACIFICORP (U901-E), an Oregon Company, for an Order Authorizing a General Rate Increase Effective January 1, 2019*, Application (A.) 18-04-002 (filed April 12, 2018).

costs, the Company is proposing a mechanism that will allow it to recover these costs in between rate cases in order to smooth out rates and minimize rate shock.

PacifiCorp is proposing an increase of its currently authorized return on equity (ROE). Based on the evidence provided in the testimony and exhibits of Mr. Steven R. McDougal, PacifiCorp will earn an overall ROE in California of negative 0.17 percent for the test period under its current rate structure. This return is less than the company's currently authorized 10.0 percent ROE. The Company is requesting and increase to its ROE to 10.5 percent as supported by the testimony of Ms. Ann E. Bulkley in this proceeding. An overall price increase of approximately $27.9 million or 25.7 percent is required to produce the 10.5 percent ROE necessary to maintain PacifiCorp's financial integrity while making the necessary capital investments to transition to a cleaner energy future.

The $27.9 million increase represents an overall base revenue requirement increase of 27.8 percent, or a 25.7 percent increase on a net basis to PacifiCorp's California retail customers to become effective January 1, 2023. Based on the results of the proposed rate spread presented in the testimony and exhibits of Mr. Robert M. Meredith, PacifiCorp's proposed increase would result in the following percentage rate changes by customer class:

Customer Class	Proposed Base Price Change	Proposed Net Price Change
Residential	27.9%	25.8%
General Service		
Schedule A-25	27.9%	25.8%
Schedule A-32	27.8%	25.8%
Schedule A-36	27.9%	25.7%
Large General Service		
Schedule AT-48	27.8%	25.7%
Irrigation		
Schedule PA-20	27.9%	25.7%
Lighting	27.7%	21.9%
Overall	27.8%	25.7%

B. Post Test Year Adjustment Mechanism (PTAM) Attrition Factor

PacifiCorp requests authorization to continue the PTAM Attrition Factor adjustment as approved in A.18-04-002. The Commission has subsequently authorized the continuation of this mechanism in decisions following the 2019 Rate Case.[2] PacifiCorp proposes that the same mechanism previously approved by the Commission be used to adjust PacifiCorp rates effective January 1 of calendar years between rate cases. This request is explained in the testimony of Mr. McVee.

III. PROCEDURAL HISTORY

A. 2019 Rate Case

The Company filed its last general rate case in California on April 12, 2018 (A.18-04-002). In that application, PacifiCorp requested an increase to its authorized base electric revenue requirement of $1.06 million or 0.9 percent.[3] During the course of the proceeding, PacifiCorp revised its requested revenue requirement to $78,591,697 which represented a $0.8 million increase to rates that had been in effect.[4] Following a fully litigated proceeding, on February 18, 2020, the Commission issued Decision (D.) 20-02-025 that approved a decrease in revenue requirement, for a final revenue requirement of $71,951,494.[5]

---

[2] *In the Matter of the Application of PacifiCorp (U901E), an Oregon Company, for an Order Authorizing a General Rate Increase Effective January 1, 2019*, A.18-04-002, D.20-02-025 Appendix A, (Feb. 18, 2020), D.21-01-006 (Jan. 15, 2021)

[3] *In the Matter of the Application of PacifiCorp (U901E), an Oregon Company, for an Order Authorizing a General Rate Increase Effective January 1, 2019*, A.18-04-002, Application and Exhibit PAC/1101, (McCoy Direct) (Apr. 12, 2018).

[4] *Id.*, Exhibit PAC/1901, (McCoy Rebuttal) (Nov. 20, 2018).

[5] *In the Matter of the Application of PacifiCorp (U901E), an Oregon Company, for an Order Authorizing a General Rate Increase Effective January 1, 2019*, A.18-04-002, D.20-02-025, Ordering Paragraph 1, Appendix A, (Feb. 18, 2020).

B. Subsequent Applications to Modify

In D.20-02-025, the Commission directed the Company to file its next general rate case for test year 2022 in accordance with the three-year rate plan adopted in D.89-01-040.[6] The Commission also directed PacifiCorp to include in its next rate case or in an earlier application its retirement plans for all coal facilities serving California customers consistent with its Integrated Resource Plan (IRP) filings.[7]

On September 18, 2020, PacifiCorp requested that the Commission modify D.20-02-025 to grant it a one-year extension to file a general rate case and to allow for an additional Post Test Year Adjustment Mechanism (PTAM) for attrition in 2021 and provide for its use in 2022. In D.21-01-006, the Commission granted the Company's requested modification, including the change in test year from 2022 to 2023.[8]

A second petition for modification was filed on February 12, 2021, because of a delay in the issuance of the Company's 2021 IRP. Specifically, the Company requested a modification to D.20-02-025 that required the Company to include in its rate case for a 2022 test year or in an earlier application, its retirement plans for all coal facilities serving California customers. PacifiCorp requested that deadline for filing these documents be extended to the filing date of its 2023 general rate case. In D.21-07-012, the Commission granted the Company's request.[9]

---

[6] *Id*, Ordering Paragraphs 11, 17, and 18.
[7] *Id.,* Ordering Paragraph 18.
[8] *In the Matter of the Application of PacifiCorp (U901E), an Oregon Company, for an Order Authorizing a General Rate Increase Effective January 1, 2019*, A.18-04-002, D.21-01-006, Ordering Paragraphs 1 and 2, (Jan 15, 2021).
[9] *In the Matter of the Application of PacifiCorp (U901E), an Oregon Company, for an Order Authorizing a General Rate Increase Effective January 1, 2019*, A.18-04-002, D.21-07-012, Ordering Paragraphs 1 and 2, (July 21, 2021).

V. STATUTORY AND REGULATORY REQUIREMENTS

A. Statutory and Other Authority (Rule 2.1)

Rule 2.1 requires that all applications state clearly and concisely the authorization or relief sought; cite by appropriate reference the statutory provision or other authority under which Commission authorization or relief is sought; and be verified by the applicant. The relief being sought is summarized in Section II above and is further described in the testimony and supporting exhibits accompanying this Application. The statutory and other authority under which this relief is being sought includes Articles 2 and 3 of the Rules, Sections 451, 454, 491, 701, 728, and 729 of the Cal. Pub. Util. Code, and prior decisions, orders, and resolutions of this Commission. This Application has been verified by an officer of PacifiCorp in accordance with the requirements of Rules 1.1 and 2.1.

B. Proposed Categorization, Need for Hearing, Issues to be Considered, and Proposed Schedule (Rule 2.1(c))

Rule 2.1(c) requires PacifiCorp to state "[t]he proposed category for the proceeding, the need for hearing, the issues to be considered, and a proposed schedule." PacifiCorp proposes that the Commission classify this proceeding as "ratesetting."[10] PacifiCorp acknowledges the need for evidentiary hearings in this matter and proposes the following procedural schedule:

Event	Estimated Timeline
Application Filed	May 5, 2022
Protests Due	30 days after filing appears on Commission's Daily Calendar
Response to Protests Due	10 days after the last day for filing a protest
Prehearing Conference	June 23, 2022
Scoping Memo Issued	July 14, 2022
Intervenor Testimony Due	August 9, 2022
PacifiCorp Rebuttal Testimony Due	September 2, 2022

[10] Rule 1.3(e) defines "Ratesetting" as "proceedings in which the Commission sets or investigates rates for a specifically named utility (or utilities), or establishes a mechanism that in turn sets the rates for a specifically named utility (or utilities). . ."

Event	Estimated Timeline
Evidentiary Hearings (anticipate 2 days)	September 20 – 21, 2022
Opening Briefs	October 7, 2022
Reply Briefs	October 10, 2022
Proposed Decision (PD) Issued	November 10, 2022
Comments on PD Due	November 30, 2022
Reply Comments on PD Due	December 5, 2022
Final Commission Decision (rates effective January 1, 2023)	December 15, 2022

C. Issues to be Considered and Relevant to Safety Considerations

The issues to be considered are described in this Application and the accompanying testimony, including the attached appendices.

In D.16-01-017, the Commission amended Rule 2.1(c) to require that applications clearly state the "relevant safety considerations." The Company is committed to promoting the health, safety, comfort and convenience of customers and the public at large. Safety for PacifiCorp employees, customers, and stakeholders is one of PacifiCorp's six core principles. PacifiCorp has developed and implemented various programs to enable the safety of its customers, employees, and stakeholders. In benchmarking with other electric utilities through the Edison Electric Institute, PacifiCorp has been consistently positioned in the top quartile among its peer companies with respect to safety performance.

PacifiCorp's safety strategy aligns with current best practices in safety management, including a dedication to thorough and effective employee and contractor training, and ongoing monitoring of safety practices in the field through job-site employee engagements by management and safety professionals, which are documented and analyzed to evaluate the effectiveness of the safety program and identify emerging risk trends. PacifiCorp continues to reduce and control safety risks through engineering controls such as battery-operated, strain-reducing tools, and safer design of vehicles and special equipment. The safety culture at

PacifiCorp is sustained by many safety endeavors. Employees and our unions are highly engaged in the development of company safety manuals and the selection of personal protective equipment. PacifiCorp maintains effective mechanisms for accountability to policies and procedures, but also embraces a learning approach to events to ensure management system and human factors are recognized and addressed to prevent future events. PacifiCorp also holds its contractors to a high standard of safety by requiring its contractors to register with a third-party evaluator of the contractor's safety performance.

The Company complies with all applicable safety codes, including, but not limited to, the National Electric Safety Code, the code of federal regulations and all corresponding state regulations pertaining to occupational health and safety. The Company audits its compliance by performing quarterly inspections, more extensive annual and biannual reviews, and through the analysis of field engagement findings and event data. The Company continuously communicates about safety in many ways including daily crew job briefing practice, daily "Safe & Secure" email messages, monthly safety meetings, and topic-specific safety bulletins. Safety committees perform an important function at PacifiCorp to ensure employee engagement and involvement in the safety management system.

The Company prioritizes safety for all resources and to the benefit of all employees, customers, and stakeholders.

D. Legal Name and Correspondence – Rules 2.1(a) and (b)

PacifiCorp is a public utility organized and existing under the laws of the state of Oregon. PacifiCorp's legal name is PacifiCorp. PacifiCorp engages in the business of generating, transmitting, and distributing electric energy in portions of northern California and in the states of Idaho, Oregon, Utah, Washington, and Wyoming. PacifiCorp's principal place of business is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232.

Communications regarding this Application should be addressed to:

Pooja Kishore
Regulatory Affairs Manager
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, Oregon 97232
Telephone: (503) 813-7314
Email: californiadockets@pacificorp.com

Carla Scarsella
Ajay Kumar
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, OR 97232
Telephone: (503) 813-6338
Email: carla.scarsella@pacificorp.com
ajay.kumar@pacificorp.com

Michael B. Day
Megan Somogyi
Downey Brand, LLP
455 Market Street, Suite 1500
San Francisco, California 94105
Telephone: (415) 848-4808
Facsimile: (415) 398-4321
E-mail: mday@downeybrand.com
msomogyi@downeybrand.com

In addition, PacifiCorp respectfully requests that all data requests regarding this matter be addressed to:

By E-mail (preferred):	datarequest@pacificorp.com
By regular mail:	Data Request Response Center PacifiCorp 825 NE Multnomah, Suite 2000 Portland, OR 97232

E. Organization and Qualification to Transact Business – (Rule 2.2)

A certified copy of PacifiCorp's Articles of Incorporation, as amended, and presently in effect, was filed with the Commission in A.97-05-011, which resulted in Commission issuance of D.97-12-093 and is incorporated herein by reference pursuant to Rule 2.2.

F. Balance Sheet and Income Statement – (Rule 3.2(a)(1))

A copy of PacifiCorp's recent financial statements, contained in the Annual Report on Form 10-K, filed February 26, 2022, with the Securities and Exchange Commission, for the period ending December 31, 2021, is included herein as Appendix A. The Company notes that even though filed on February 26, 2022, the Form 10-K was posted to the Securities and Exchange Commission's website on February 28, 2022. In this Application, the Company will refer to the filing date of the Form 10-K.

G. Present and Proposed Rates – (Rule 3.2(a)(2) and (3))

Accompanying this application are Exhibits PAC/1100 through PAC/1109, the testimony and exhibits sponsored by Company witness Robert M. Meredith, which reflect the present and proposed rates.

H. List of Testimony and Appendices Accompanying this Application

PacifiCorp's submissions to support this Application include the following:

Appendix A is PacifiCorp's 10-K Annual Report for the period ending December 31, 2021, and filed with the Securities and Exchange Commission on February 26, 2022.

Appendix B is Berkshire Hathaway, Inc.'s definitive proxy statement (Form DEF 14A) filed with the Securities and Exchange Commission on March 11, 2022.

Exhibit PAC/100: Matthew McVee, PacifiCorp's Vice President, Regulatory Policy and Operations, presents an overview of PacifiCorp's application, describes the Company's request to continue certain authorized cost recovery mechanisms, explains the Company's proposal to revise the depreciable lives for certain coal-fueled generation units; and describes the Company's proposal to return to customers the revenues received from the sale of renewable energy certificates associated with the Pryor Mountain Wind

Project. Mr. McVee also introduces the other Company witnesses submitting testimony in support of the rate case filing.

Exhibits PAC/200 through PAC/211: Ann E. Bulkley, Principal at The Brattle Group, provides a comparison of PacifiCorp's business and financial risk compared to peer utilities, recommends a cost of equity, and provides supporting analyses.

Exhibits PAC/300 through PAC/308: Nikki L. Kobliha, PacifiCorp's Chief Financial Officer, provides the overall cost of capital recommendation for the Company, including a capital structure to maximize value and minimize risk and the current cost of debt. Ms. Kobliha also addresses the 2018 Depreciation Study.

Exhibits PAC/400: Shayleah J. LaBray, PacifiCorp's Vice President of Resource Planning and Acquisitions, describes the economic analysis performed to support PacifiCorp's decision to acquire and repower Foote Creek II, III and IV wind energy facilities. Ms. LaBray also provides information on the Company's retirement plans for all coal units serving California customers. Finally, she discusses the load forecast used in this filing.

Exhibit PAC/500: James Owen, PacifiCorp's Vice President of Environmental, Fuels, and Mining, explains how state and federal environmental requirements for PacifiCorp's coal-fueled power plants are accounted for in the Company's long-term resource planning process and how these requirements drive the retirement dates or in some cases, conversion dates of certain coal units.

Exhibits PAC/600 through PAC/602: Ryan D. McGraw, PacifiCorp's Vice President of Project Development, supports and explains the Company's decommissioning studies, the costs of which are incorporated in this proceeding.

Exhibits PAC/700 through PAC/702: Timothy J. Hemstreet, PacifiCorp's Managing Director of Renewable Energy Development, supports the prudency of the Company's efforts to acquire and repower the Foote Creek II, III, and IV wind energy facilities.

Exhibits PAC/800 through PAC/801: Allen Berreth, PacifiCorp's Vice President of Transmission and Distribution Operations, supports the Company's risk-based investment in certain transmission and distribution investments, including wildfire mitigation. Mr. Berreth also discusses vegetation management expenses.

Exhibits PAC/900 through PAC/907: Steven R. McDougal, PacifiCorp's Managing Director of Revenue Requirement, summarizes the overall 2023 test year revenue requirement, pro forma adjustments, and the rate base calculation methodology. Mr. McDougal also discusses the Company's inter-jurisdictional cost allocation methodology (2020 Protocol).

Exhibits PAC/1000 through PAC/1002: André T. Lipinski, PacifiCorp's Senior Pricing and Cost of Service Analyst, presents the functional revenue requirements and supports the marginal cost-of-service study used in this filing.

Exhibits PAC/1100 through PAC/1109: Robert M. Meredith, PacifiCorp's Director of Pricing and Tariff Policy, provides the Company's proposed rate spread, rate design, and tariff changes to recover the proposed 2023 revenue requirement to achieve fair, just, and reasonable prices for customers.

I. General Description of Property and Equipment – (Rule 3.2(a)(4))

Accompanying this Application are Exhibits PAC/900 through PAC/907, the testimony and exhibits sponsored by Mr. McDougal. Mr. McDougal's testimony and exhibits contain a general description of PacifiCorp's property and equipment, and its original cost, along with a statement of the applicable depreciation reserve.

J. Summary of Earnings – (Rule 3.2(a)*(*5))

Accompanying this Application are Exhibits PAC/900 through PAC/907, the testimony and exhibits sponsored by Mr. McDougal. Mr. McDougal's testimony and exhibits provide the summary of earnings on a depreciated rate base for the test period.

K. Earnings of PacifiCorp Stated for California Operations and for the Total Company – (Rule 3.2(a)(6))

Accompanying this Application are Exhibits PAC/900 through PAC/907, the testimony and exhibits sponsored by Mr. McDougal. Mr. McDougal's testimony and exhibits include a statement of earnings stated on both a total-company basis and California-allocated basis.

L. Method of Computing Depreciation Deduction – (Rule 3.2(a)(7))

For federal income tax purposes, PacifiCorp uses the applicable depreciation methods prescribed by the Internal Revenue Code in a manner that is intended to maximize the tax deduction for tax depreciation. The same applicable depreciation methods used by PacifiCorp for federal income tax purposes are used by PacifiCorp for the purposes of calculating federal income taxes in the test period for this ratemaking filing.

M. Annual Report – Subsequent Matters – (Rule 3.2(a)(8))

Pursuant to Cal. Pub. Util. Code §587 and D.97-12-088 (as modified), PacifiCorp filed its Affiliated Interest Report for Calendar Year 2020 with the Commission on May 27, 2021 (AI Report). A copy of Berkshire Hathaway, Inc.'s most recent definitive Proxy Statement filed March 11, 2022, with the Securities and Exchange Commission is included as Appendix B. Berkshire Hathaway, Inc. is the ultimate parent of PacifiCorp.

N. Statement of Basis for Requested Increase – (Rule 3.2 (a)(10))

The rate increase requested by PacifiCorp through this Application reflects and passes through to customers both increased costs and savings to the utility for providing electric service to its customers within California. PacifiCorp's proposed rate increase is primarily due to several factors, including, among other things, increased operating expenses and Company investments related to wildfire mitigation and vegetation management.

O. Public Notice – (Rule 3.2(b), (c), and (d))

The cities and counties that would be affected by the rate changes resulting from this Application include the cities and towns of Yreka, Crescent City, Alturas, Mount Shasta, Weed, Dunsmuir, Fort Jones, Dorris, and Tulelake. The counties affected by this Application are Siskiyou, Del Norte, Modoc, and Shasta. As provided in Rule 3.2(b), (c), and (d), notice of filing of this Application will be: (1) mailed to the appropriate officials of the State of California, specifically the Attorney General and Department of General Services, and the counties and cities listed above; (2) published in a newspaper of general circulation in each county in PacifiCorp's service territory within which the rate changes would be effective; (3) included with regular bills mailed to all customers affected by the proposed changes; and (4) mailed to any other persons whom PacifiCorp deems appropriate.

IV. CONCLUSION

PacifiCorp respectfully requests that the Commission issue an order, effective January 1, 2023, approving the rate increase proposed herein.

Respectfully submitted May 5, 2022, at San Francisco, California.

By: Carla Scarsella
Carla Scarsella

Carla Scarsella
Ajay Kumar
PacifiCorp
825 NE Multnomah, Suite 2200
Portland, OR 97232
Telephone: 503-813-6338
Email: carla.scarsella@pacificorp.com
ajay.kumar@pacificorp.com

DOWNEY BRAND, LLP
Michael B. Day
Megan Somogyi
455 Market Street, Suite 1500
San Francisco, California 94105
Telephone: (415) 848-4808
E-mail: mday@downeybrand.com
msomogyi@downeybrand.com

Attorneys for PacifiCorp

OFFICER VERIFICATION

(Rule 1.11)

I am an officer of the reporting corporation herein, and am authorized to make this verification on its behalf. The statements in the foregoing document are true of my own knowledge, except as to matters which are therein stated on information or belief, and as to those matters I believe them to be true.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed on May 5, 2022, at Portland, Oregon.

Matthew McVee
Vice President, Regulatory Policy and Operations
PacifiCorp

Appendix A

PacifiCorp's Form 10-K Annual Report
for the period ending December 31, 2021

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, 2021

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)** **6603 West Broad Street** **Richmond, Virginia 23230** **804-613-5100**	**46-3639580**

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

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

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

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	☒	☐

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	☐	☒

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	☒	☐

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	☐	☐	☒	☐	☐

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 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, 2022, 76,368,874 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, 2022, 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, 2022.

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, 2022, 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, 2022, 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, 2022, 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, 2022.

Berkshire Hathaway Energy Company, MidAmerican Funding, LLC, MidAmerican Energy Company, Nevada Power Company, Sierra Pacific Power Company and Eastern Energy Gas Holdings, LLC 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 and Eastern Energy Gas Holdings, LLC. 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.

TABLE OF CONTENTS

PART I

Item 1.	Business	1
Item 1A.	Risk Factors	81
Item 1B.	Unresolved Staff Comments	95
Item 2.	Properties	95
Item 3.	Legal Proceedings	96
Item 4.	Mine Safety Disclosures	97

PART II

Item 5.	Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities	98
Item 6.	[Reserved]	99
Item 7.	Management's Discussion and Analysis of Financial Condition and Results of Operations	99
Item 7A.	Quantitative and Qualitative Disclosures About Market Risk	99
Item 8.	Financial Statements and Supplementary Data	100
Item 9.	Changes in and Disagreements With Accountants on Accounting and Financial Disclosure	453
Item 9A.	Controls and Procedures	453
Item 9B.	Other Information	453

PART III

Item 10.	Directors, Executive Officers and Corporate Governance	454
Item 11.	Executive Compensation	455
Item 12.	Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	462
Item 13.	Certain Relationships and Related Transactions, and Director Independence	463
Item 14.	Principal Accountant Fees and Services	464

PART IV

Item 15.	Exhibits and Financial Statement Schedules	465
Item 16.	Form 10-K Summary	465
Signatures		490

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
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 and Eastern Energy Gas Holdings, LLC 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 and Eastern Energy Gas Holdings, LLC and its subsidiaries
Northern Powergrid	Northern Powergrid Holdings Company
BHE GT&S	BHE GT&S, LLC and its subsidiaries
Northern Natural Gas	Northern Natural Gas Company
Kern River	Kern River Gas Transmission Company
BHE Canada	BHE Canada Holdings Corporation
AltaLink	AltaLink, L.P.
BHE U.S. Transmission	BHE U.S. Transmission, LLC
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
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
EGTS	Eastern Gas Transmission and Storage, Inc.
GT&S Transaction	The acquisition of substantially all of the natural gas transmission and storage business of Dominion Energy, Inc. and Dominion Energy Questar Corporation, exclusive of Dominion Energy Questar Pipeline, LLC and related entities on November 1, 2020
DEI	Dominion Energy, Inc.
Dominion Questar	Dominion Energy Questar Corporation
Questar Pipeline Group	Dominion Energy Questar Pipeline, LLC and related entities
Liquefaction Facility	A natural gas export/liquefaction facility
Atlantic Coast Pipeline	Atlantic Coast Pipeline, LLC
Dominion Energy Gas Restructuring	The acquisition of CPMLP Holdings Company, LLC and Eastern MLP Holding Company II, LLC from, and the disposition of the East Ohio Gas Company and Eastern Gathering and Processing, Inc. to, Dominion Energy, Inc. by Eastern Energy Gas Holdings, LLC on November 6, 2019
DCP	CPMLP Holdings Company, LLC

Certain Industry Terms

2017 Tax Reform	The Tax Cuts and Jobs Act enacted on December 22, 2017, effective January 1, 2018
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	United States Court of Appeals for the District of Columbia Circuit
DEAA	Deferred Energy Accounting Adjustment
DOE	United States Department of Energy

Dodd-Frank Reform Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
DOT	United States 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	United States Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
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
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	United States 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
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, 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 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, 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, including the wildfires that began in September 2020 in Oregon and California, and any other wildfires for which the cause has yet to be determined; 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 outcome of any legal proceedings initiated against the respective Registrant; the risk that the respective Registrant is not able to recover costs from insurance, or through rates; and the effect on the respective Registrant's reputation of such wildfires, investigations and proceedings;
- 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 where the Registrants may be found liable for property damages regardless of fault;
- 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;
- changes in the respective Registrant's credit ratings;
- 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 businesses principally engaged in the energy industry and is a consolidated subsidiary of Berkshire Hathaway. As of January 31, 2022, Berkshire Hathaway, family members and related or affiliated entities of the late Mr. Walter Scott, Jr., a former member of BHE's Board of Directors, and Mr. Gregory E. Abel, BHE's Chair, beneficially owned 91.1%, 7.9% and 1.0%, respectively, of BHE's voting common stock.

Berkshire Hathaway Energy'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 United States serving customers in 11 states, two electricity distribution companies in Great Britain, five interstate natural gas pipeline companies, one of which owns an LNG import, export and storage facility, in the United States, an electric transmission business in Canada, interests in electric transmission businesses in the United States, a renewable energy business primarily investing in wind, solar, geothermal and hydroelectric projects, the largest residential real estate brokerage firm in the United States and one of the largest residential real estate brokerage franchise networks in the United States.

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 United States and in Great Britain and Canada.

- 86% of Berkshire Hathaway Energy's consolidated operating income during 2021 was generated from rate-regulated businesses.
- The Utilities serve 5.2 million electric and natural gas customers in 11 states in the United States, Northern Powergrid serves 3.9 million end-users in northern England and AltaLink serves approximately 85% of Alberta, Canada's population.
- As of December 31, 2021, the Company owns approximately 34,500 MWs of generation capacity in operation and under construction:
    - Approximately 29,400 MWs of generation capacity is owned by its regulated electric utility businesses;
    - Approximately 5,100 MWs of generation capacity is owned by its nonregulated subsidiaries, the majority of which provides power to utilities under long-term contracts;
    - Owned generation capacity in operation and under construction consists of 39% wind and solar, 31% natural gas, 24% coal, 5% hydroelectric and geothermal and 1% nuclear and other; and,
    - Cumulative investments in (i) owned wind, solar and geothermal generation facilities of $30.1 billion and (ii) wind projects sponsored by third parties, commonly referred to as tax equity investments, of $5.9 billion.
- The Company owns approximately 36,000 miles of transmission lines and owns a 50% interest in ETT that has approximately 1,900 miles of transmission lines.
- The BHE Pipeline Group operates approximately 21,100 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 United States during 2021 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 over $189.4 billion of home sales in 2021, up 24.4% from 2020, and continued to grow its brokerage, mortgage and franchise businesses, with services in all 50 states. HomeServices' franchise business has approximately 360 franchisees primarily in the United States and internationally.

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, 2021, BHE had approximately 23,600 employees, consisting of approximately 13,400 (57%) electric and natural gas operations employees, approximately 6,700 (28%) real estate services employees and approximately 3,500 (15%) corporate services employees. HomeServices has approximately 46,000 real estate agents who are independent contractors. As of December 31, 2021, approximately 8,400 BHE 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

Safety and security are integral to the Registrants' culture and will always be one 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 one-year period. The recordable incident rates for each of the Registrants are included below:

	Year Ended December 31, 2021
Recordable Incident Rate:	
PacifiCorp	0.50
MidAmerican Energy	0.67
Nevada Power	0.77
Sierra Pacific	0.74
Eastern Energy Gas	0.18
BHE Overall	0.35

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 and holiday benefits; and
- Career development opportunities that provide access to a variety of learning programs and career development support, including tuition reimbursement.

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 United States regulated electric utility company headquartered in Oregon that serves approximately 2.0 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 and 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:

	2021		2020		2019	
Utah	25,657	46 %	24,851	46 %	24,490	45 %
Oregon	13,510	24	12,993	24	13,089	24
Wyoming	8,557	15	8,358	15	9,393	17
Washington	4,199	8	4,065	7	4,145	7
Idaho	3,553	6	3,534	7	3,485	6
California	798	1	759	1	741	1
Total	56,274	100 %	54,560	100 %	55,343	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:

	2021		2020		2019	
GWhs sold:						
Residential	17,905	29 %	17,150	29 %	16,668	27 %
Commercial	18,839	31	17,727	29	18,151	30
Industrial	17,909	29	18,039	30	19,049	31
Other	1,621	3	1,644	3	1,475	3
Total retail	56,274	92	54,560	91	55,343	91
Wholesale	5,113	8	5,249	9	5,480	9
Total GWhs sold	61,387	100 %	59,809	100 %	60,823	100 %
Average number of retail customers (in thousands):						
Residential	1,745	87 %	1,713	87 %	1,682	87 %
Commercial	222	11	217	11	214	11
Industrial	9	1	9	1	10	1
Other	27	1	28	1	27	1
Total	2,003	100 %	1,967	100 %	1,933	100 %

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

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 2021, PacifiCorp's peak demand was 10,861 MWs in the summer and 8,736 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, 2021:

Generating Facility	Location	Energy Source	Installed / Repowered[1]	Facility Net Capacity (MWs)[2]	Net Owned Capacity (MWs)[2]
COAL:					
Jim Bridger Nos. 1, 2, 3 and 4[3]	Rock Springs, WY	Coal	1974-1979	2,119	1,413
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
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
				8,583	5,234
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	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
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	Arlington, WY	Wind	1999 / 2021	41	41
McFadden Ridge	McFadden, WY	Wind	2009 / 2019	28	28
				2,254	2,254
HYDROELECTRIC:					
Lewis River System	WA	Hydroelectric	1931-1958	578	578
North Umpqua River System	OR	Hydroelectric	1950-1956	204	204
Klamath River System	CA, OR	Hydroelectric	1903-1962	170	170
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	26	26
				1,135	1,135
OTHER:					
Blundell	Milford, UT	Geothermal	1984, 2007	32	32
				32	32
Total Available Generating Capacity				15,247	11,668

(1) Repowered dates are associated with component replacements on existing wind-powered generating facilities commonly referred to by the 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 at rates that depend upon the date on which construction begins.

(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) Jim Bridger Units 1 and 2 are currently operating under a consent decree as described in "Environmental Laws and Regulations" in Item 1 of this Form 10-K.

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

	2021	2020	2019
Coal	48 %	48 %	53 %
Natural gas	20	19	19
Wind(1)	10	6	3
Hydroelectric and other(1)	5	5	5
Total energy generated	83	78	80
Energy purchased - long-term contracts (renewable)(1)	15	12	10
Energy purchased - short-term contracts and other	2	10	10
	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 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. 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 hydroelectric and wind-powered 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 and Bridger underground coal mines. The Bridger underground mine ceased coal production in November 2021. These mines supplied 21%, 16% and 19% of PacifiCorp's total coal requirements during the years ended December 31, 2021, 2020 and 2019, respectively. The remaining coal requirements for PacifiCorp's coal-fueled generating facilities are acquired through long- and short-term third-party contracts.

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%. Recoverability by underground mining techniques ranges from 50% to 70%. To meet applicable standards, PacifiCorp blends coal from its owned mines 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 contracts to supply its generating facilities over their currently expected remaining useful lives.

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.

Hydroelectric

The amount of electricity PacifiCorp is able to generate from its hydroelectric facilities depends on a number of factors, including snowpack in the mountains upstream of its hydroelectric 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 84% 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.

Wind and Other Renewable Resources

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. Between 2019 and 2021, PacifiCorp repowered all of its existing wind-powered generating facilities by replacing a significant portion of the equipment to requalify the facilities for federal renewable electricity PTCs for 10 years from the date the repowered facilities were placed in-service. Repowering extended the lives of the existing wind facilities and increased the anticipated electrical generation from the repowered wind facilities, on average, by approximately 26%. Additionally, new wind-powered generating facilities totaling 516 MWs were placed in-service during 2021. The energy production from the new wind-powered generating facilities is expected to qualify for 100% of the federal PTCs available for 10 years from the date the equipment 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.

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 United States. 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 United States 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.

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 17,000 miles of transmission lines in 10 states, 64,400 miles of distribution lines and 900 substations as of December 31, 2021.

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 United States 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 over $8 billion, primarily in Wyoming, Utah, Idaho and Oregon. The over $8 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 Aeolus substation near Medicine Bow in Wyoming and 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 with Idaho Power and the Bonneville Power Administration), expected to be placed in-service in 2026; and (h) other 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, 2021, $2.9 billion had been spent and $2.4 billion, including AFUDC, had been placed in-service.

Future Generation, Conservation and Energy Efficiency

Energy Supply Planning

As required by certain state regulations, PacifiCorp uses an IRP to develop a long-term resource plan to ensure that PacifiCorp can continue to provide reliable and cost-effective electric service to its customers while maintaining compliance with existing and evolving environmental laws and regulations. The IRP process identifies the amount and timing of PacifiCorp's expected future resource needs, accounting for planning uncertainty, risks, reliability, state energy policies and other factors. The IRP is prepared following a public process, which provides an opportunity for stakeholders to participate in PacifiCorp's resource planning process. PacifiCorp files its IRP on an every-two-year basis 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.

In September 2021, PacifiCorp filed its 2021 IRP with its state commissions outlining resources through 2040. The IRP includes investments in new renewable energy resources, new battery storage resources, expanded transmission investments and advanced nuclear resources. New renewable energy resources in the IRP include more than 1,800 MWs of new wind-powered generation, over 2,100 MWs of new solar-powered generation and nearly 700 MWs of new battery storage capacity by 2025. The IRP also outlines PacifiCorp's plan to retire or convert to natural gas all coal-fueled resources by 2042. An RFP associated with the 2021 IRP will be issued to the market by May 1, 2022 with a final shortlist expected in June 2023.

Requests for Proposals

PacifiCorp issues individual RFPs, each of which typically focuses on a specific category of generation resources consistent with the IRP or other customer-driven demands. The IRP and the RFPs provide for the identification and staged procurement of resources to meet load or RPS requirements. 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 issued the 2020 All Source RFP to the market in July 2020. The 2020 All Source RFP sought bids for resources capable of coming online by the end of 2024 up to the level of resources identified in PacifiCorp's 2019 IRP. An initial shortlist was identified in October 2020. The final shortlist of winning bids was submitted to the OPUC in June 2021. PacifiCorp will initiate negotiations with shortlisted bids that include approximately 1,792 MWs of new wind capacity, 1,306 MWs of solar capacity and 697 MWs of battery storage to its portfolio by 2024. PacifiCorp expects that 590 MWs of the 1,792 MWs of new wind capacity will be owned with the remainder of the wind, solar and battery storage capacity being contracted resources.

Energy Efficiency Programs

PacifiCorp has provided a comprehensive set of DSM programs to its customers 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 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 2021, PacifiCorp spent $154 million on these DSM programs, resulting in an estimated 500,000 MWhs of first-year energy savings and an estimated 284 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. Recovery of the costs associated with the large industrial load management program are captured in the retail special contract agreements with those customers approved by their respective state commissions or through PacifiCorp's general rate case process.

Human Capital

Employees

As of December 31, 2021, PacifiCorp had approximately 4,800 employees, of which approximately 57% 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 United States 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. Metropolitan areas in which MidAmerican Energy distributes electricity at retail include Council Bluffs, Des Moines, Fort Dodge, Iowa City, Sioux City and Waterloo, Iowa; and the Quad Cities (Davenport and Bettendorf, Iowa and Rock Island, Moline and East Moline, Illinois). Metropolitan areas in which it distributes natural gas at retail include Cedar Rapids, Des Moines, Fort Dodge, Iowa City, Sioux City and Waterloo, Iowa; the Quad Cities; and Sioux Falls, South Dakota. 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 or two 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):

	2021		2020		2019	
Operating revenue:						
Regulated electric	$ 2,529	71 %	$ 2,139	79 %	$ 2,237	76 %
Regulated gas	1,003	28	573	21	660	23
Other	15	1	8	—	28	1
Total operating revenue	$ 3,547	100 %	$ 2,720	100 %	$ 2,925	100 %
Operating income:						
Regulated electric	$ 358	86 %	$ 384	86 %	$ 473	86 %
Regulated gas	58	14	64	14	71	13
Other	—	—	—	—	4	1
Total operating income	$ 416	100 %	$ 448	100 %	$ 548	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:

	2021		2020		2019	
Iowa	25,909	92 %	24,425	92 %	24,073	92 %
Illinois	1,895	7	1,847	7	1,894	7
South Dakota	270	1	251	1	234	1
	28,074	100 %	26,523	100 %	26,201	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:

	2021		2020		2019	
GWhs sold:						
Residential	6,718	15 %	6,687	18 %	6,575	18 %
Commercial	3,841	9	3,707	10	3,921	11
Industrial	15,944	36	14,645	39	14,127	39
Other	1,571	4	1,484	4	1,578	4
Total retail	28,074	64	26,523	71	26,201	72
Wholesale	16,011	36	11,219	29	10,000	28
Total GWhs sold	44,085	100 %	37,742	100 %	36,201	100 %
Average number of retail customers (in thousands):						
Residential	690	86 %	682	86 %	675	86 %
Commercial	98	12	97	12	95	12
Industrial	2	—	2	—	2	—
Other	14	2	14	2	14	2
Total	804	100 %	795	100 %	786	100 %

Variations in weather, economic conditions and various conservation and energy efficiency measures and programs can impact customer usage. 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, July, August and 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 24%, 23% and 21% of total retail electric sales in 2021, 2020 and 2019, respectively. Sales to electronic data storage customers included in the 10 largest customers comprised 16%, 16% and 12% of total retail electric sales in 2021, 2020 and 2019, 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 June 17, 2021, retail customer usage of electricity caused a new record hourly peak demand of 5,236 MWs on MidAmerican Energy's electric distribution system, which is 141 MWs greater than the previous record hourly peak demand of 5,095 MWs set July 19, 2019.

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, 2021:

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	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	310	310
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
Century	Blairsburg, IA	Wind	2005-2008 / 2017-2018	200	200
Eclipse	Adair, IA	Wind	2012	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	120	120
Macksburg	Macksburg, IA	Wind	2014	119	119
Contrail	Braddyville, IA	Wind	2020	110	110
Morning Light	Adair, IA	Wind	2012	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
				7,186	7,186
COAL:					
Louisa	Muscatine, IA	Coal	1983	746	656
Walter Scott, Jr. Unit No. 3	Council Bluffs, IA	Coal	1978	705	558
Walter Scott, Jr. Unit No. 4	Council Bluffs, IA	Coal	2007	811	484
George Neal Unit No. 3	Sergeant Bluff, IA	Coal	1975	514	370
Ottumwa	Ottumwa, IA	Coal	1981	704	366
George Neal Unit No. 4	Salix, IA	Coal	1979	650	264
				4,130	2,698
NATURAL GAS AND OTHER:					
Greater Des Moines	Pleasant Hill, IA	Gas	2003-2004	480	480
Electrifarm	Waterloo, IA	Gas or Oil	1975-1978	182	182
Pleasant Hill	Pleasant Hill, IA	Gas or Oil	1990-1994	156	156
Sycamore	Johnston, IA	Gas or Oil	1974	144	144

Generating Facility	Location	Energy Source	Year Installed / Repowered[1]	Facility Net Capacity (MWs)[2]	Net Owned Capacity (MWs)[2]
River Hills	Des Moines, IA	Gas	1966-1967	117	117
Coralville	Coralville, IA	Gas	1970	67	67
Moline	Moline, IL	Gas	1970	64	64
27 portable power modules	Various	Oil	2000	54	54
Parr	Charles City, IA	Gas	1969	33	33
				1,297	1,297
NUCLEAR:					
Quad Cities Unit Nos. 1 and 2	Cordova, IL	Uranium	1972	1,823	456
HYDROELECTRIC:					
Moline Unit Nos. 1-4	Moline, IL	Hydroelectric	1941	4	4
Total Available Generating Capacity				14,440	11,641
PROJECTS UNDER CONSTRUCTION:					
Various solar projects				141	141
				14,581	11,782

(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 at rates that depend upon the date on which construction begins.

(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:

	2021	2020	2019
Wind and other renewable[1]	52 %	54 %	44 %
Coal	27	19	33
Nuclear	9	10	10
Natural gas	3	2	1
Total energy generated	91	85	88
Energy purchased - short-term contracts and other	8	14	10
Energy purchased - long-term contracts (renewable)[1]	1	1	1
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.

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 United States 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 92% of MidAmerican Energy's wind-powered generating capacity in-service at December 31, 2021, are authorized to earn over their regulatory lives a fixed rate of return on equity ranging from 11.0% 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 from 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 2031. Since 2014, MidAmerican Energy has repowered, or plans to repower, 2,204 MWs of wind-powered generating facilities for which PTCs have expired or will expire by the end of 2022. Based on initial estimates, MidAmerican Energy anticipates energy generation from the repowered facilities will increase between 19% and 30% depending upon the technology being repowered.

Of the 7,335 MWs (nameplate capacity) of wind-powered generating facilities in-service as of December 31, 2021, 6,717 MWs were generating PTCs, including 1,387 MWs of repowered facilities. PTCs earned by MidAmerican Energy's wind-powered generating facilities placed in-service prior to 2013, except for repowered facilities, are included in MidAmerican Energy's Iowa EAC, through which MidAmerican Energy is allowed to recover fluctuations in its electric retail energy costs. Facilities earning PTCs that currently benefit customers through the Iowa EAC totaled 407 MWs (nominal ratings) as of December 31, 2021, with the eligibility of those facilities to earn PTCs expiring by the end of 2022. MidAmerican Energy earned PTCs totaling $574 million and $510 million in 2021 and 2020, respectively, of which 12% and 15%, 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 2025. MidAmerican Energy believes supplies from these sources are presently adequate and available to meet MidAmerican Energy's needs. MidAmerican Energy's coal supply portfolio has substantially all of its expected 2022 and 2023 requirements 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 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 Corp. ("Constellation Energy", previously Exelon Generation Company, LLC, which was a subsidiary of Exelon Corporation prior to February 1, 2022), 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 does not anticipate it will have difficulty in obtaining 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. The proceeds from the ZECs will provide Constellation Energy additional revenue through 2027 as an incentive for continued operation of Quad Cities Station.

Natural Gas and Other

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

Regional Transmission Organizations

MidAmerican Energy sells and purchases electricity and ancillary services related to its generation and load in wholesale markets pursuant to the tariffs in those markets. MidAmerican Energy participates predominantly in the MISO energy and ancillary service markets, which provide MidAmerican Energy with wholesale opportunities over a large market area. MidAmerican Energy can enter into wholesale bilateral transactions in addition to market activity related to its assets. MidAmerican Energy is also authorized to participate in the Southwest Power Pool, Inc. and PJM Interconnection, L.L.C. ("PJM") markets and can contract with several other utilities in the region. MidAmerican Energy can utilize both 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 reserve margin of its accredited generating capacity over its peak demand obligation based on the member's load forecast filed with the MISO each year. The MISO's reserve requirement was 9.4% for the summer of 2021 and will decrease to 8.7% for the summer of 2022. MidAmerican Energy's owned and contracted capacity accredited for the 2021-2022 MISO capacity auction was 5,704 MWs compared to a peak demand obligation of 4,938 MWs, or a reserve margin of 15.5%. 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, or design, 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 4,600 circuit miles of transmission lines in four states, 25,200 circuit miles of distribution lines and 340 substations as of December 31, 2021. 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 2021, 59% 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 24,200 miles of natural gas main and service lines as of December 31, 2021.

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:

	2021	**2020**	**2019**
Iowa	76 %	76 %	76 %
South Dakota	13	13	13
Illinois	10	10	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:

	2021	2020	2019
Residential	44 %	45 %	45 %
Commercial(1)	20	20	22
Industrial(1)	5	5	4
Total retail	69	70	71
Wholesale(2)	31	30	29
	100 %	100 %	100 %
Total Dths of natural gas sold (in thousands)	111,916	114,399	125,655
Total Dths of transportation service (in thousands)	112,631	110,263	112,143
Total average number of retail customers (in thousands)	781	774	766

(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 January 29, 2019, MidAmerican Energy recorded its all-time highest peak-day delivery through its distribution system of 1,319,361 Dths. This peak-day delivery consisted of 68% traditional retail sales service and 32% transportation service. MidAmerican Energy's 2021/2022 winter heating season peak-day delivery as of February 2, 2022, was 1,268,053 Dths, reached on January 25, 2022. This preliminary peak-day delivery consisted of 60% traditional retail sales service and 40% 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 respective jurisdictional 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 2021/2022 winter heating season preliminary peak-day of January 25, 2022, supply sources used to meet deliveries to traditional retail sales service customers included 58% from purchases delivered on interstate pipelines, 38% from interstate pipeline storage services and 4% 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 demand- and energy-reduction 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 2021, $47 million was expensed for MidAmerican Energy's energy efficiency programs, which resulted in estimated first-year energy savings of 120,000 MWhs of electricity and 182,000 Dths of natural gas and an estimated peak load reduction of 382 MWs of electricity and 2,506 Dths per day of natural gas.

Human Capital

Employees

All of MidAmerican Funding's employees are employed by MidAmerican Energy. As of December 31, 2021, MidAmerican Energy had approximately 3,400 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, 2022. 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 United States 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 United States 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 20- to 25-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 2021, 82% 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):

	2021		2020		2019	
Operating revenue:						
Electric	$ 848	88 %	$ 738	86 %	$ 770	87 %
Gas	117	12	116	14	119	13
Total operating revenue	$ 965	100 %	$ 854	100 %	$ 889	100 %
Operating income:						
Electric	$ 148	89 %	$ 147	89 %	$ 150	88 %
Gas	19	11	18	11	21	12
Total operating income	$ 167	100 %	$ 165	100 %	$ 171	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:

	2021		2020		2019	
Nevada Power:						
GWhs sold:						
Residential	10,415	44 %	10,477	46 %	9,311	41 %
Commercial	4,838	21	4,591	20	4,657	21
Industrial	5,270	22	4,881	21	5,344	24
Other	198	1	195	1	193	1
Total fully bundled	20,721	88	20,144	88	19,505	87
Distribution only service	2,646	11	2,425	11	2,613	12
Total retail	23,367	99	22,569	99	22,118	99
Wholesale	356	1	374	1	527	1
Total GWhs sold	23,723	100 %	22,943	100 %	22,645	100 %
Average number of retail customers (in thousands):						
Residential	871	88 %	856	88 %	840	88 %
Commercial	112	12	110	12	109	12
Industrial	2	—	2	—	2	—
Total	985	100 %	968	100 %	951	100 %
Sierra Pacific:						
GWhs sold:						
Residential	2,769	23 %	2,672	23 %	2,491	22 %
Commercial	3,056	26	2,977	26	2,973	26
Industrial	3,716	31	3,544	31	3,716	32
Other	15	—	15	—	16	—
Total fully bundled	9,556	80	9,208	80	9,196	80
Distribution only service	1,639	14	1,670	15	1,629	14
Total retail	11,195	94	10,878	95	10,825	94
Wholesale	656	6	548	5	662	6
Total GWhs sold	11,851	100 %	11,426	100 %	11,487	100 %
Average number of retail customers (in thousands):						
Residential	316	87 %	310	86 %	304	86 %
Commercial	49	13	49	14	48	14
Total	365	100 %	359	100 %	352	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 usage. 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, 48-52% 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 9, 2021, customer usage of electricity caused an hourly peak demand of 6,300 MWs on Nevada Power's electric system, which is 176 MWs more than the record hourly peak demand of 6,124 MWs set July 28, 2016. On July 12, 2021, customer usage of electricity caused an hourly peak demand of 2,106 MWs on Sierra Pacific's electric system, which is 200 MWs more than the previous record hourly peak demand of 1,906 MWs set July 29, 2020.

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, 2021:

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	1,142	1,142
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	589	589
Silverhawk	Las Vegas, NV	Natural gas	2004	520	520
Las Vegas	Las Vegas, NV	Natural gas	1994-2003	272	272
Sun Peak	Las Vegas, NV	Natural gas/oil	1991	210	210
				4,463	4,463
RENEWABLES:					
Nellis	Las Vegas, NV	Solar	2015	15	15
Goodsprings	Goodsprings, NV	Waste heat	2010	5	5
				20	20
Total Available Generating Capacity				4,483	4,483
Sierra Pacific:					
NATURAL GAS:					
Tracy	Sparks, NV	Natural gas	1974-2008	737	737
Ft. Churchill	Yerington, NV	Natural gas	1968-1971	196	196
Clark Mountain	Sparks, NV	Natural gas	1994	132	132
				1,065	1,065
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				1,607	1,346
Total NV Energy Available Generating Capacity				6,090	5,829
PROJECTS UNDER CONSTRUCTION:					
Dry Lake	Dry Lake, NV	Solar	Est. 2023	150	150
				6,240	5,979

(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.

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

	2021	2020	2019
Nevada Power:			
Natural gas	64 %	66 %	65 %
Coal	—	—	5
Total energy generated	64	66	70
Energy purchased - long-term contracts (renewable)[1]	19	15	17
Energy purchased - long-term contracts (non-renewable)	10	13	11
Energy purchased - short-term contracts and other	7	6	2
	100 %	100 %	100 %
Sierra Pacific:			
Natural gas	43 %	48 %	46 %
Coal	11	8	11
Total energy generated	54	56	57
Energy purchased - long-term contracts (renewable)[1]	17	15	13
Energy purchased - short-term contracts and other	15	5	3
Energy purchased - long-term contracts (non-renewable)	14	24	27
	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.

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 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, natural gas and coal. Nevada Power has entered into contracts with a total capacity of 3,612 MWs with contract termination dates ranging from 2022 to 2067. Included in these contracts are 3,352 MWs of capacity from renewable energy, of which 1,818 MWs of capacity are under development or construction and not currently available. Sierra Pacific has entered into contracts with a total capacity of 1,159 MWs with contract termination dates ranging from 2022 to 2047. Included in these contracts are 973 MWs of capacity from renewable energy, of which 300 MWs of capacity are under development or construction and not currently available.

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

Natural Gas

The Nevada Utilities rely on first-of-the-month 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 2021, natural gas supply net purchases averaged 317,177 and 157,083 Dths per day with the winter period contracts averaging 262,019 and 178,185 Dths per day and the summer period contracts averaging 356,097 and 142,194 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 coal purchase agreement that extends through December 2023. The Valmy generating facility, Sierra Pacific's remaining facility requiring coal, has an approved retirement date of December 2025. 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 United States. 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 United States 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 United States. 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, 14,000 miles of distribution lines and 210 substations as of December 31, 2021. Sierra Pacific's transmission and distribution systems included approximately 4,200 miles of transmission lines, 9,500 miles of distribution lines and 210 substations as of December 31, 2021.

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 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 to the Northwest substation to the Harry Allen substation; a 235-mile, 525-kV transmission line, known as Greenlink North, connecting the new Ft. Churchill substation to the Robinson Summit substation; a 46-mile, 345-kV transmission line from the new Ft. Churchill substation to the Mira Loma substations; and a 38-mile, 345-kV transmission line from the new Ft. Churchill substation to the Robinson Summit substations. The Greenlink program will be constructed in stages that are estimated to be placed in-service between December 2026 and December 2028. The Nevada Utilities will jointly own and operate the Greenlink transmission lines.

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 July 2020, the Nevada Utilities filed their fourth amendment to the IRP requesting approval of two new renewable energy power purchase agreements, a utility-owned renewable facility, a utility-owned community scale renewable facility and updates to the Transmission Plan which includes a 350-mile, 525-kV transmission line known as Greenlink West. In July 2020, the Nevada Utilities also filed a joint petition requesting to defer the September 2020 filing of the Updated DRP until its June 2021 Joint IRP is filed. In September 2020, the PUCN issued an order granting the petition to defer the filing and ordered the Nevada Utilities to conduct an informal workshop in October 2020 to provide an update of the DRP and present information consistent with the statutory requirements. In November 2020, the Nevada Utilities filed a settlement stipulation of the fourth amendment to the IRP, which was followed by a hearing. The settlement resolved all issues related to the load forecast, four renewable energy projects and certain transmission investments. The stipulation was approved by the PUCN in December 2020. In February 2021, a hearing was held and in March 2021, the PUCN issued an order granting the Transmission Plan in part and denying in part. The order approved construction of a major segment of Greenlink West connecting the Ft. Churchill substation to the Northwest substation and denied construction of the remaining segments of Greenlink West at this time but instead approved design, permitting and land acquisition of the remaining segments.

In June 2021, the Nevada Utilities filed a joint application for approval of their 2022-2041 Triennial IRP, 2022-2024 ESP and 2022-2024 Action Plan. As part of the filing, the Nevada Utilities requested approval of 600 MWs of solar photovoltaic generating resources with 480 MWs of battery energy storage capacity, three battery energy storage projects with 66 MWs of capacity, the acquisition of one existing solar photovoltaic generating facility with 19.5 MWs of capacity that is currently leased to Sierra Pacific, and network upgrades associated with the new renewable energy projects. In September 2021, a hearing was held for the generation upgrades portion of the application, which resulted in an order approving that portion of the joint IRP. The Nevada Utilities filed a partial party stipulation resolving all issues related to the ESP, load forecast and fuel and purchased power price portions of the joint IRP. In October 2021, the Nevada Utilities filed a corrected stipulation, which was approved by the PUCN. In November 2021, a hearing was conducted for the remaining portions of the joint IRP and in December 2021, the PUCN issued an order granting in part and denying in part. The PUCN approved the construction of the 600 MWs of solar photovoltaic generating resources with 480 MWs of battery energy storage capacity, the acquisition of the existing solar photovoltaic generating facility and the network upgrade, among other items. However, the three additional battery energy storage projects were deferred for approval in future plans and the PUCN declined to retire Valmy 1 early and made adjustments to the approved budget for developing and conducting the distributed resource energy trial.

In September 2021, in compliance with Senate Bill ("SB") 448, the Nevada Utilities filed an amendment to the 2021 joint IRP for approval of their Transmission Infrastructure for a Clean Energy Economy Plan that sets forth a plan for the construction of certain high-voltage transmission infrastructure which includes a 235-mile, 525-kV transmission line known as Greenlink North and a 32-mile, 525-kV transmission segment of Greenlink West. In January 2022, the Nevada Utilities reached a settlement with all the intervening parties and presented a stipulation before the PUCN related to the Greenlink transmission project. The settlement allows for the Nevada Utilities to receive approval to construct the Greenlink North project and the remaining segment of the Greenlink West project. The settlement allows the Nevada Utilities to designate these projects as critical facilities that will allow the Nevada Utilities to propose financial incentives in future proceedings. Potential financial incentives include construction work in process included in rate base and the ability to use regulatory asset accounting treatment. The Nevada Utilities agreed not to seek an enhanced return on investment at the state level as part of the settlement. The stipulation was approved by the PUCN in January 2022.

Emissions Reduction and Capacity Replacement Plan

In compliance with SB 123, Nevada Power retired 255 MWs of coal-fueled generation in 2019 in addition to the 557 MWs of coal-fueled generation retired in 2017. Consistent with the Emissions Reduction and Capacity Replacement Plan ("ERCR Plan"), between 2014 and 2016, Nevada Power acquired 536 MWs of natural gas generating resources, executed long-term power purchase agreements for 200 MWs of nameplate renewable energy capacity and constructed a 15-MW solar photovoltaic facility. Nevada Power has the option to acquire 35 MWs of nameplate renewable energy capacity in the future under the ERCR Plan, subject to PUCN approval.

Energy Efficiency Programs

The Nevada Utilities have provided a comprehensive set of 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, 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. 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 2021, Nevada Power spent $35 million on energy efficiency programs, resulting in an estimated 224,000 MWhs of electric energy savings and an estimated 173 MWs of electric peak load management. During 2021, Sierra Pacific spent $10 million on energy efficiency programs, resulting in an estimated 65,000 MWhs of electric energy savings and an estimated 18 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 2021, 9% 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 3,500 miles of natural gas mains and service lines as of December 31, 2021.

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:

	2021	2020	2019
Residential	53 %	56 %	57 %
Commercial[1]	28	28	29
Industrial[1]	10	10	10
Total retail	91	94	96
Wholesale[2]	9	6	4
	100 %	100 %	100 %
Total Dths of natural gas sold (in thousands)	20,050	18,622	19,846
Total Dths of transportation service (in thousands)	1,807	1,850	2,217
Total average number of retail customers (in thousands)	177	174	170

(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 25, 2021, Sierra Pacific recorded its highest peak-day natural gas delivery of 137,226 Dths, which is 26,348 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, 2021, Nevada Power had approximately 1,300 employees, of which approximately 700 were covered by a union contract with the International Brotherhood of Electrical Workers.

As of December 31, 2021, Sierra Pacific had approximately 900 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 and a hydrocarbon exploration and development business that is focused on developing integrated upstream gas projects in Europe and Australia.

The Northern Powergrid Distribution Companies serve 3.9 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 2021, E.ON and certain of its affiliates and British Gas Trading Limited represented 23% and 12%, 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.

During 2021, 28 energy suppliers ceased trading due to rising wholesale prices, particularly for natural gas. This has resulted in energy supply costs being higher than the Ofgem set variable tariff price cap they can charge customers. Any distribution use of system bad debts suffered by Northern Powergrid is recoverable in future distribution use of systems revenue with a three-year time lag.

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 the Ofgem and limit increases to allowed revenues (or may require decreases) based upon the rate of inflation, other specified factors and other regulatory action. Changes to the price controls can be made by the regulator, but if a licensee disagrees with a change to its license, it can appeal the matter to the United Kingdom's Competition and Markets Authority ("CMA"). 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. The current electricity distribution price control became effective April 1, 2015 and will continue through March 31, 2023.

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:

	2021		2020		2019	
Northern Powergrid (Northeast) plc:						
Residential	5,410	40 %	5,252	40 %	4,982	36 %
Commercial	1,480	11	1,411	11	1,644	12
Industrial	6,561	48	6,377	48	7,097	51
Other	125	1	142	1	156	1
	13,576	100 %	13,182	100 %	13,879	100 %
Northern Powergrid (Yorkshire) plc:						
Residential	7,924	39 %	7,694	39 %	7,311	35 %
Commercial	2,163	11	2,048	11	2,391	12
Industrial	9,863	49	9,540	49	10,722	52
Other	193	1	217	1	236	1
	20,143	100 %	19,499	100 %	20,660	100 %
Total electricity distributed	33,719		32,681		34,539	
Number of end-users (in thousands):						
Northern Powergrid (Northeast) plc	1,616		1,615		1,612	
Northern Powergrid (Yorkshire) plc	2,325		2,319		2,314	
	3,941		3,934		3,926	

As of December 31, 2021, the combined electricity distribution network of the Northern Powergrid Distribution Companies included approximately 17,400 miles of overhead lines, 43,300 miles of underground cables and 780 major substations.

BHE PIPELINE GROUP (EASTERN ENERGY GAS)

BHE GT&S

BHE GT&S is an indirect wholly owned subsidiary of BHE. 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, a field service company, and a gathering and processing company.

Eastern Energy Gas' principal subsidiaries are EGTS and Carolina Gas Transmission, LLC ("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 southeastern 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 transportation 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 owns a 25% limited partnership interest in the Cove Point LNG export, import and storage facility. 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. Eastern Energy Gas also operates 17 underground storage fields with a total working gas capacity of approximately 420 Bcf, of which approximately 306 Bcf relates to natural gas storage field capacity that Eastern Energy Gas owns.

BHE GT&S' pipeline system is configured with approximately 370 active receipt and delivery points. In 2021, 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 transportation 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. Approximately 92% of BHE GT&S' transmission capacity is subscribed including 89% under long-term contracts and 3% on a year-to-year basis. As of December 31, 2021, the weighted average remaining contract term for Eastern Energy Gas' firm transportation contracts is eight years. BHE GT&S' storage services are 99% subscribed with long-term contracts with an average remaining contract term of four years. Additionally, BHE GT&S receives revenue from firm fee-based contractual arrangements, including negotiated rates, for certain pipeline transportation 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):

	2021		
Transportation	$	772	36 %
LNG		704	32
Storage		251	12
Gas, liquids and other sales		433	20
Total operating revenue	$	2,160	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 2021, BHE GT&S had two customers that each accounted for greater than 10% of its operating revenue and its 10 largest customers accounted for 52% 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

Employees

As of December 31, 2021, Eastern Energy Gas had approximately 1,500 employees, consisting of approximately 1,100 natural gas operations employees and 400 corporate services employees. As of December 31, 2021, approximately 600 employees were covered by a union contract with the Utility Workers Union of America. For more information regarding Eastern Energy Gas' human capital disclosures, refer to Item 1. Business - General section of this Form 10-K.

Northern Natural Gas

Northern Natural Gas, an indirect wholly owned subsidiary of BHE, owns the largest interstate natural gas pipeline system in the United States, 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 14,300 miles of natural gas pipelines, including 5,800 miles of mainline transmission pipelines and 8,500 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 1.4 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 2,244 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 1.2 Tcf of natural gas to its customers in 2021.

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. In addition, Northern Natural Gas has fixed rates that are market-based for certain of its firm storage contracts with contract terms that expire in 2028.

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

	2021		2020		2019	
Transportation:						
Market Area	$ 658	61 %	$ 633	65 %	$ 544	64 %
Field Area - deliveries to Demarc	92	9	137	14	106	12
Field Area - other deliveries	85	8	89	10	95	11
Total transportation	835	78	859	89	745	87
Storage	94	9	91	9	65	8
Total transportation and storage revenue	929	87	950	98	810	95
Gas, liquids and other sales	143	13	18	2	42	5
Total operating revenue	$ 1,072	100 %	$ 968	100 %	$ 852	100 %

Substantially all of Northern Natural Gas' Market Area transportation revenue is generated from reservation charges, with the balance from usage charges. Northern Natural Gas transports natural gas primarily to local distribution markets and end-users in the Market Area. Northern Natural Gas provides service to 83 utilities, including MidAmerican Energy, an affiliate company, which serve numerous residential, commercial and industrial customers. 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, 2021, approximately 65% of Northern Natural Gas' customers' entitlement in the Market Area have terms beyond 2023 and approximately 46% beyond 2026. As of December 31, 2021, 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 and midstream companies, which take advantage of the price spread opportunities created between Field Area supply points and Demarc. In addition, there are a growing number of midstream customers that are delivering gas south in the Field Area to the Waha Hub market. The remaining Field Area transportation service is sold to power generators connected to Northern Natural Gas' system in Texas and New Mexico that are contracted on a long-term basis with a weighted average remaining contract term of six years, and various LDCs, energy marketing companies and midstream companies for both connected and off-system markets.

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 over 2.2 Bcf per day of peak delivery capability. These storage facilities provide operational flexibility for the daily balancing of Northern Natural Gas' system and provide services to customers for their winter peaking and year-round load swing requirements. Northern Natural Gas has 65.1 Bcf of firm storage contracts with an average remaining contract term for firm storage contracts of five years.

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 2021, 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 2029 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.

Northern Natural Gas' extensive pipeline system, which is interconnected with many interstate and intrastate pipelines in the national grid system, has access to multiple major supply basins. Direct access is available from producers in the Anadarko, Permian and Hugoton basins, some of which have experienced increased production from shale and tight sands formations adjacent to Northern Natural Gas' pipeline. Since 2011, the pipeline has connected 2,565,000 Dths per day of supply access from the Midland and Delaware Basins within the Permian Basin area in west Texas and from the Granite Wash tight sands formations in the Texas panhandle and in Oklahoma. Additionally, Northern Natural Gas has interconnections with several interstate pipelines and several intrastate pipelines with receipt, delivery, or bi-directional capabilities. Because of Northern Natural Gas' location and multiple interconnections it is able to access natural gas from other key production areas, such as the Rocky Mountain, Williston, including the Bakken formation, and western Canadian basins. The Rocky Mountain basins are accessed through interconnects with Trailblazer Pipeline Company, Tallgrass Interstate Gas Transmission, LLC, Cheyenne Plains Gas Pipeline Company, LLC, Colorado Interstate Gas Company and Rockies Express Pipeline, LLC ("REX"). The western Canadian basins are accessed through interconnects with Northern Border Pipeline Company ("Northern Border"), Great Lakes Gas Transmission Limited Partnership ("Great Lakes") and Viking Gas Transmission Company ("Viking"). This supply diversity and access to both stable and growing production areas provides significant flexibility to Northern Natural Gas' system and customers.

Northern Natural Gas' system experiences significant seasonal swings in demand and revenue typically with approximately two-thirds of transportation revenue occurring during the months of November through March. This seasonality provides Northern Natural Gas with opportunities to deliver additional value-added services, such as firm and interruptible storage services. As a result of Northern Natural Gas' geographic location in the middle of the United States and its many interconnections with other pipelines, Northern Natural Gas has the opportunity to augment its steady end user and LDC revenue by capitalizing on opportunities for shippers to reach additional markets, such as Chicago, Illinois, other parts of the Midwest, and Texas, through interconnects.

Kern River

Kern River, an indirect wholly owned subsidiary of BHE, 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 design capacity of 2,166,575 Dths, or 2.2 Bcf, per day. 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 and stores natural gas for utilities, municipalities, gas marketing companies, industrial and commercial users. Except for quantities of natural gas owned for operational purposes, Kern River does not own the natural gas that is transported through its system. Kern River's transportation rates are cost-based. The 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.

Kern River's rates are based on a levelized rate design with 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, 2021, initial Period One contracts total 331,921 Dths per day. Period Two contracts total 1,113,024 Dths per day and 538,333 Dths per day of total turned back volume has an average remaining contract term of more than six years. The remaining capacity is sold on a short-term basis at market rates.

As of December 31, 2021, approximately 86% of Kern River's design capacity 2,166,575 Dths per day 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 78% 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 April 2022 and October 2036 and have a weighted-average remaining contract term of over eight years. Kern River's customers include 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 of December 31, 2021, 74% of the firm capacity under contract has primary delivery points in California, with the flexibility to access secondary delivery points in Nevada and Utah. In 2020, Kern River provided approximately 25% of California's demand for natural gas.

During 2021, Kern River had two customers, including Nevada Power 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.

Competition

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. Legislation and governmental regulations, weather, futures markets, production costs and other factors beyond the control of the Pipeline Companies, influence the price of the natural gas commodity. Additionally, natural gas demand could be adversely affected by laws mandating or incenting renewable power sources that produce fewer GHG emissions than natural gas.

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. The Pipeline Companies' ability to extend existing customer contracts, remarket expiring contracted capacity or market new capacity is dependent on competitive alternatives, the regulatory environment and the market supply and demand factors at the relevant dates these contracts are eligible to be renewed or extended. The duration of new or renegotiated contracts will be affected by current commodity and transportation prices, competitive conditions and customers' judgments concerning future market trends and volatility.

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' natural gas transmission operations compete with domestic and Canadian pipeline companies. The combination of reliable and flexible services, access to highly liquid and attractive pricing locations, significant storage capability, availability of numerous receipt and delivery points along its pipeline system and capacity rights held on third-party pipelines enables BHE GT&S to tailor its services to meet the needs of individual customers.

Northern Natural Gas needs to compete aggressively to serve existing load and add new load. Northern Natural Gas' attractive competitive position relative to other pipelines in the upper Midwest is reinforced each winter as customers expect, and receive, reliable deliveries of natural gas for their critical markets. Northern Natural Gas provides customers access to multiple supply basins that allow customers to obtain reliable supplies at competitive prices, not subject to the natural gas grid dynamics from pipeline competition that would limit customers to a singular supply source. Northern Natural Gas has been successful in competing for a significant amount of the increased demand related to residential and commercial needs and the construction of new generating facilities and new fertilizer or other industrial plants.

Other than the short-term transportation associated with the Permian business, Northern Natural Gas expects the current level of Field Area contracting to Demarc to continue in the foreseeable future, as Market Area customers presently need to purchase competitively-priced supplies from the Field Area to support their existing and growth demand requirements. However, the revenue received from these Field Area contracts is expected to decrease due to construction of new pipeline facilities.

Kern River is the only interstate pipeline that presently delivers natural gas directly from the Rocky Mountain gas supply region to end-users in the Southern California market. Kern River's levelized rate structure and access to upstream pipelines, storage facilities and economic Rocky Mountain gas reserves increase its competitiveness and attractiveness to end-users. Kern River believes it has an advantage relative to other interstate pipelines serving Southern California because its relatively new pipeline can be economically expanded and has required significantly less capital expenditures and ongoing maintenance than other systems.

Cove Point's gas transportation, LNG import and storage operations, as well as the Liquefaction Facility's capacity, are contracted primarily under long-term fixed reservation fee agreements. However, in the future Cove Point may compete with other independent terminal operators as well as major oil and gas companies on the basis of terminal location, services provided and price. In addition, the Liquefaction Facility may face competition on a global scale as international customers explore other options to meet their energy needs.

BHE TRANSMISSION

BHE Canada

BHE Canada, an indirect wholly owned subsidiary of BHE, 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 8,200 miles of transmission lines and approximately 310 substations as of December 31, 2021, 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 kVs to 500 kVs. 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 June 2021, the AESO released the 2021 Long-term Outlook, which is the AESO's forecast of Alberta's load and generation over the next 20 years and is used as the foundation of the AESO's Long-Term Transmission Plan. The 2021 Long-term Outlook includes a Reference Case scenario, which is the AESO's main forecast for long-term load growth and generation development in Alberta, and a set of alternative scenarios that are developed to understand future uncertainties. The 2021 Long-term Outlook Reference Case forecasts a reduction in load growth from the 0.8% in the 2019 Long-term Outlook to 0.5% over the next 20 years due to lower economic and oil sands production outlooks. The Reference Case forecasts over 12,000 MWs of new or substantially modified generation over the next 20 years with increased reliance on natural gas generation and strong growth in renewables. In addition to the Reference Case scenario, the AESO included a Clean-Tech scenario, a robust demand for global oil and gas scenario, and a stagnant demand for global oil and gas scenario.

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 has a reduced pace of growth as compared to the 2020 Long-Term Transmission Plan. Several projects in the 2020 Long-Term Transmission Plan totaling approximately C$1 billion have been deferred by several years in the 2022 Long-Term Transmission Plan. The 2022 Long-Term Transmission Plan identifies potential investment in the range of C$150 million to C$200 million per year on average over a 10-year period, with 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.

BHE Canada also owns MATL Canada L.P., a company headquartered in Alberta, Canada, which operates 82 miles of the 230-kV Montana Alberta Tie Line located in Canada (the entire transmission line runs from Lethbridge, Alberta, Canada to Great Falls, Montana, United States and connects power grids in the two jurisdictions), NAT-1 L.P., a company headquartered in Alberta, Canada, which operates a 20-MW natural gas generation facility located in Ralston, Alberta, and BHE Canada Rattlesnake, L.P., a company headquartered in Alberta, Canada, which is developing a 130-MW wind farm near Medicine Hat, Alberta that is expected to be in-service in 2022.

BHE U.S. Transmission

BHE U.S. Transmission, a wholly owned subsidiary of BHE, is engaged in various joint ventures to develop, own and operate transmission assets and is pursuing additional investment opportunities in the United States. Currently, BHE U.S. Transmission has two joint ventures with transmission assets that are operational. In May 2020, BHE U.S. Transmission acquired the general partner and limited partner interests in MATL LLP, a U.S based company with 132 line miles in the United States of the total 214-mile 230-kV line running from Lethbridge, Alberta, Canada to Great Falls, Montana.

BHE U.S. Transmission indirectly owns a 50% interest in ETT, along with subsidiaries of American Electric Power Company, Inc. ("AEP"). ETT owns and operates electric transmission assets in the ERCOT and, as of December 31, 2021, had total assets of $3.4 billion. ETT's transmission system includes approximately 1,900 miles of transmission lines and 39 substations as of December 31, 2021.

BHE U.S. Transmission also indirectly owns a 25% interest in Prairie Wind Transmission, LLC, a joint venture with AEP and Evergy, Inc., to build, own and operate a 108-mile, 345-kV transmission project in Kansas. The project had total assets of $133 million as of December 31, 2021.

BHE RENEWABLES

The subsidiaries comprising the BHE Renewables reportable segment own interests in several independent power projects in the United States. The following table presents certain information concerning these independent power projects as of December 31, 2021:

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
Walnut Ridge	Illinois	Wind	2018	2028	USGSA	212	212
Flat Top	Texas	Wind	2019	2031	Citi Commodities	200	200
Pinyon Pines I	California	Wind	2012	2035	SCE	168	168
Gopher Creek	Texas	Wind	2019	2024	JP Morgan	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
						2,077	2,077
SOLAR:							
Topaz	California	Solar	2013-2014	2039	PG&E	550	550
Solar Star 1	California	Solar	2013-2015	2035	SCE	310	310
Solar Star 2	California	Solar	2013-2015	2035	SCE	276	276
Agua Caliente	Arizona	Solar	2012-2013	2039	PG&E	290	142
Alamo 6	Texas	Solar	2017	2042	CPS	110	110
Community Solar Gardens[6]	Minnesota	Solar	2016-2018	2041-2043	(5)	98	98
Pearl	Texas	Solar	2017	2042	CPS	50	50
						1,684	1,536
NATURAL GAS:							
Cordova	Illinois	Natural Gas	2001	NA	NA	512	512
Power Resources	Texas	Natural Gas	1988	NA	NA	212	212
Saranac	New York	Natural Gas	1994	NA	NA	245	196
Yuma	Arizona	Natural Gas	1994	2024	SDG&E	50	50
						1,019	970
GEOTHERMAL:							
Imperial Valley Projects	California	Geothermal	1982-2000	(3)	(3)	345	345
						345	345
HYDROELECTRIC:							
Wailuku	Hawaii	Hydroelectric	1993	2023	HELCO	10	10
						10	10
Total Available Generating Capacity						5,135	4,938

(1) San Diego Gas & Electric Company ("SDG&E"); Pacific Gas and Electric Company ("PG&E"), Ameren Illinois Company ("Ameren"), Southern California Edison ("SCE"), Hawaii Electric Light Company, Inc. ("HELCO"); Austin Energy ("AE"); Omaha Public Power District ("OPPD"); Kimberly-Clark Corporation ("KC"); City of Denton, TX ("CODTX"); MidAmerican Energy Services, LLC ("MES"); U.S. General Services Administration ("USGSA"); Missouri Joint Municipal Electric Commission ("MJMEC"); Kansas Power Pool ("KPP"); Kansas Municipal Energy Agency ("KMEA"); City of Independence, MO ("COIMO"); CPS Energy ("CPS"); and Central Iowa Power Cooperative ("CIPCO").

(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):

	2021		2020		2019	
Solar	$ 468	48 %	$ 455	48 %	$ 449	48 %
Wind	160	16	183	20	195	21
Geothermal	178	18	173	18	177	19
Hydro	32	3	26	3	20	2
Natural gas	143	15	99	11	91	10
Total operating revenue	$ 981	100 %	$ 936	100 %	$ 932	100 %

HOMESERVICES

HomeServices, a wholly owned subsidiary of BHE, is the largest residential real estate brokerage firm in the United States. 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 over 900 offices in 33 states and the District of Columbia with approximately 46,000 real estate agents under 55 brand names. The United States 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 360 franchisees primarily in the United States and internationally in over 1,600 brokerage offices with over 53,000 real estate agents under two brand names. 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.

OTHER ENERGY BUSINESSES

MES is a nonregulated energy business consisting of competitive electricity and natural gas retail sales. MES' electric operations predominantly include sales to retail customers in Illinois, Texas, Pennsylvania, Ohio, Maryland and other states that allow customers to choose their energy supplier. MES' natural gas operations predominantly include sales to retail customers in Iowa and Illinois. Electricity and natural gas are purchased from producers and third-party energy marketing companies and sold directly to commercial, industrial and governmental end-users. MES does not own electricity or natural gas production assets but hedges its contracted sales obligations either with physical supply arrangements or financial products. As of December 31, 2021, MES' contracts in place for the sale of electricity totaled 17,230 GWhs with an average term of 2.8 years and for the sale of natural gas totaled 20,392,527 Dths with an average term of 1.2 years. In addition, MES manages natural gas supplies for a number of smaller commercial end-users, which includes the sale of natural gas to these customers to meet their supply requirements. Refer to Item 7A in this Form 10-K for a discussion of commodity price risk and derivative contracts.

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 a fair opportunity to earn a 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 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 as well. 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 the 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 proceeds from the sale of RECs. Effective January 1, 2021, Annual Wildfire Mitigation and Vegetation Management Cost Recovery Mechanism approved for three years 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 three years, the mechanism will be assessed to determine whether continued use is warranted.
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). 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, there are two options for temporary collection of higher rates following the filing of a request for a base rate increase. Collection can begin, subject to refund, either (1) within 10 days of filing, without IUB review, or (2) 90 days after filing, with approval by the IUB, depending upon the ratemaking principles and precedents utilized. In either case, if the IUB has not issued a final order within 10 months after the filing date, the temporary rates become final and any difference between the requested rate increase and the temporary rates may then be collected subject to refund until receipt of a final order. 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 6,639 MWs (nominal ratings) of wind-powered generating facilities as of December 31, 2021. 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, 2021, the generating facilities in-service totaled $7.9 billion, or 39%, 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 11.4% 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 XII 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 placed in-service in 2016 under the Wind X project and facilities constructed under the Wind XII project approved by the IUB in 2018. Rate base reductions under these mechanisms are applied to coal and other generation facilities in specified orders.

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. The Iowa mechanism also includes PTCs associated with wind-powered generating facilities placed in-service prior to 2013, except for PTCs earned by repowered facilities. Eligibility for PTCs associated with MidAmerican Energy's earliest projects began expiring in 2014. Facilities currently earning PTCs that benefit customers through the Iowa EAC totaled 407 MWs (nominal ratings) as of December 31, 2021, with the eligibility of those facilities to earn PTCs expiring by the end of 2022. 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, operations and maintenance expense or income tax benefit, as applicable.

Of the wind-powered generating facilities placed in-service as of December 31, 2021, 5,007 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 2017 Tax Reform, which enacted significant changes to the Internal Revenue Code, including, among other things, a reduction in the United States federal corporate income tax rate from 35% to 21%. South Dakota implemented changes to base rates in response to 2017 Tax Reform. As a result of 2017 Tax Reform, 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 from 12% to 9.8% effective in 2021, at which time, the impacts of Iowa Senate File 2417 began to be included in the Iowa tax expense revision mechanism.

NV Energy (Nevada Power and Sierra Pacific)

Rate Filings

Nevada statutes require the Nevada Utilities to file electric general rate cases at least once every three years with the PUCN. 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, 2021, the cumulative installed and applied-for capacity of net metering systems under AB 405 in Nevada was 421 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.

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 $1.4 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 2019 and an order accepting it was issued in September 2020. 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 2020 and an order accepting it was issued in December 2020. 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 2020 and is under review by the FERC. 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.

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, 19 developments associated with PacifiCorp's hydroelectric generating facilities licensed with the FERC 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 operating licenses.

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 United States. Currently, MidAmerican Energy's aggregate maximum potential share of an assessment for Quad Cities Station is approximately $69 million per incident, payable in installments not to exceed $10 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 and non-nuclear damage losses up to $500 million. 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 $7 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.

United States Mine Safety

PacifiCorp's 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. Federal law requires PacifiCorp to have a written emergency response plan specific to each underground mine it operates, which is reviewed by the Federal Mine Safety and Health Administration every six months, and to have at least two mine rescue teams located within one hour of each mine. 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 import/export 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. Generally, the FERC will require an Environmental Impact Statement for nearly all natural gas projects it reviews, encouraging environmental impact mitigation, will incorporate further analysis with respect to environmental justice and will require a greater showing of need for a project, particularly in the event the project is for service to an affiliate.

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 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 and define and map locations by mid-2021 and complete 50% of the required integrity testing by 2028 and the remaining testing by 2034. The BHE Pipeline Group has updated procedures, identified pipeline segments subject to the rule and has planned projects to complete required assessments. The gas gathering rule was included in 2021 and has limited impact on the BHE Pipeline Group. The third and final part of the anticipated new rule is expected in 2022.

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 1 ("ED1"), has been set for a period of eight years, starting April 1, 2015, although the formula has been, and may be, reviewed by the regulator following public consultation. 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.

A new price control can be implemented by GEMA without the consent of the DNOs, but 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, 2015, as did one other party, and the CMA subsequently revised GEMA's decision.

The current eight-year electricity distribution price control period runs from April 1, 2015 through March 31, 2023. The current price control was the first to be set for electricity distribution in Great Britain since Ofgem completed its review of network regulation (known as the RPI-X @ 20 project). The key changes to the price control calculations, compared to those used in previous price controls are that:

- the period over which new regulatory assets are depreciated is being gradually lengthened, from 20 years to 45 years, with the change being phased over eight years;
- allowed revenues will be adjusted during the price control period, rather than at the next price control review, to partially reflect cost variances relative to cost allowances;
- the allowed cost of debt will be updated within the price control period by reference to a long-run trailing average based on external benchmarks of utility debt costs;
- allowed revenues will be adjusted in relation to some new service standard incentives, principally relating to speed and service standards for new connections to the network; and
- there was scope for a mid-period review and adjustment to revenues in the latter half of the period for any changes in the outputs required of licensees for certain specified reasons, although GEMA made no adjustments under this provision.

Under the current price control, as revised by the CMA, and excluding the effects of incentive schemes and any deferred revenues from the prior price control, the opening base allowed revenue of Northern Powergrid (Northeast) plc and Northern Powergrid (Yorkshire) plc remains constant in all subsequent years within the price control period (ED1) through 2022-23, before the addition of inflation. Nominal opening base allowed revenues will increase in line with inflation. Adjustments are made annually to recognize the effect of factors such as changes in the allowed cost of debt, performance on incentive schemes and catch up of prior year under- or over- recoveries.

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, Gopher Creek, Flat Top, 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 are generally 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 using 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 marketer CalEnergy, 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 2019 and an order accepting it was issued in March 2020. 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 2020 and an order accepting it was issued in December 2020. 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 2020 and an order accepting it was issued in March 2021. 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 and is awaiting FERC action.

The entire output of Jumbo Road, Santa Rita, Gopher Creek, Flat Top, 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 United States 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 United States Federal Trade Commission with respect to certain franchising activities; by the United States 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 March 2020, PacifiCorp filed its annual EBA application with the UPSC requesting recovery of $37 million of deferred net power costs from customers for the period January 1, 2019 through December 31, 2019, reflecting the difference between base and actual net power costs in the 2019 deferral period. This reflected a 1.0% increase compared to current rates. The UPSC approved the request in February 2021 for rates effective March 1, 2021.

In March 2021, PacifiCorp filed its annual EBA application with the UPSC requesting recovery of $2 million of deferred net power costs from customers for the period January 1, 2020 through December 31, 2020, reflecting the difference between base and actual net power costs in the 2020 deferral period. This reflected a $36 million reduction, or 1.7% decrease compared to current rates. In June 2021, PacifiCorp updated the requested recovery to $7 million to correct certain load related data reflected in the initial application. The updated recovery request reflects a $31 million reduction, or 1.5%, decrease compared to current rates. In January 2022, PacifiCorp filed an uncontested stipulation agreement providing for full recovery of the requested $7 million. The UPSC approved the stipulation agreement as filed in February 2022.

In August 2021, PacifiCorp filed an application with the UPSC for alternative cost recovery of a major plant addition to recover the incremental revenue requirement related to the delayed portions of the Pryor Mountain and TB Flats wind-powered generating facilities that are not currently reflected in rates from the last general rate case. PacifiCorp's request would result in a net decrease of $4 million, or 0.2%, in base rates effective January 1, 2022. Requested recovery of $7 million for the capital related cost is offset by $7 million related to forecast PTCs and $4 million in net power cost savings with actual PTCs and net power cost savings to be trued-up in the EBA. In December 2021, the UPSC concluded PacifiCorp's request did not qualify for recovery under the major plant additions statute and denied the application.

In August 2021, PacifiCorp filed an application with the UPSC for approval of its Electric Vehicle Infrastructure Program as provided for by Utah House Bill 396 ("HB 396"), Electric Vehicle Charging Infrastructure Amendments. The filing details how PacifiCorp proposes to invest the $50 million authorized by HB 396 to support the development of electric vehicle infrastructure in Utah. In November 2021, PacifiCorp reached a settlement stipulation with most of the intervening parties resolving all issues. The remaining intervening parties are not signatories but did not oppose the stipulation. The new program provides funding for both utility-owned charging equipment and make-ready infrastructure; establishes a new tariff for charging rates at PacifiCorp-owned stations, initially set at 45 cents per kilowatt-hour for the general public with a 40% discount for PacifiCorp's Utah customers; creates a new surcharge to collect $50 million over 10 years from Utah customers to fund the program; establishes annual reporting to the UPSC with a program review every three years; and extends the residential time-of-use pilot rates. The surcharge replaced the existing Sustainable Transportation and Energy Plan cost adjustment that expired on December 31, 2021. In December 2021, the UPSC approved the settlement stipulation, resulting in a decrease of $5 million, or 0.2%, compared to current rates effective January 1, 2022.

Oregon

In February 2020, PacifiCorp filed a general rate case and in December 2020, the OPUC approved a net rate decrease of approximately $24 million, or 1.8%, effective January 1, 2021, accepting PacifiCorp's proposed annual credit to customers of the remaining 2017 Tax Reform benefits over a two-year period. PacifiCorp's compliance filing to reset base rates effective January 1, 2021 in response to the OPUC's order reflected a rate decrease of approximately $67 million, or 5.1%, due to the exclusion of the impacts of repowered wind-powered generating facilities, new wind-powered generating facilities and certain other new investments that had not been placed in-service at the time of the filing. Additional compliance filings have been made to include investments in rates concurrent with when they were placed in-service. In January 2021, the OPUC approved the second compliance filing to add the remainder of the Ekola Flats wind-powered generating facility to rates, resulting in a rate increase of approximately $7 million, or 0.5%, effective January 12, 2021. In April 2021, the OPUC approved the third compliance filing to add the Foote Creek repowered wind-powered generating facility and the Pryor Mountain new wind-powered generating facility to rates, resulting in a rate increase of $14 million, or 1.2%, effective April 9, 2021. In July 2021, a deferral for resources not placed in-service by June 30, 2021 was filed for consideration in a future rate proceeding.

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 requests an initial rate increase of $35 million, or 2.8%, effective January 1, 2022, to recover the incremental costs from those approved in the last general rate case.

In April 2021, PacifiCorp submitted its annual TAM filing in Oregon requesting an increase of $1 million, or 0.1%, effective January 1, 2022, based on forecast net power costs and loads for the calendar year 2022. In July 2021, PacifiCorp filed a reply with an amended net power costs which updated its 2022 TAM to a $2 million rate increase. In November 2021, the OPUC approved PacifiCorp's 2022 TAM, subject to adjustments, reducing PacifiCorp's requested net power cost amount and resulting in an overall annual rate decrease of approximately $15 million, or 1.2 %, effective January 1, 2022.

In May 2021, Oregon's governor signed Oregon House Bill 2165 requiring electric companies to collect funding to support and integrate transportation electrification. In July 2021, Oregon's governor signed Oregon House Bill 3141 addressing changes related to public purpose and energy efficiency rates. In November 2021, PacifiCorp filed an advice letter to address the legislative changes adopted in House Bills 2165 and 3141. In December 2021, the OPUC approved the advice filing. The filing resulted in an overall rate increase of approximately $5 million, or 0.4%, effective January 1, 2022.

In July 2021, Oregon's governor signed Oregon House Bill 2739 requiring electric companies to collect an additional $10 million per calendar year for low-income electric bill payment and crisis assistance beginning January 1, 2022. In November 2021, PacifiCorp filed an advice letter to revise the rates, and the OPUC approved the advice filing in December 2021. The filing resulted in an overall rate increase of $4 million, or 0.3%, effective January 1, 2022, representing PacifiCorp's share.

Wyoming

In September 2018, PacifiCorp filed an application for depreciation rate changes with the WPSC based on PacifiCorp's 2018 depreciation rate study, requesting the rates become effective January 1, 2021. Updates since September 2018 include the filing of PacifiCorp's 2020 decommissioning studies in which a third-party consultant was engaged to estimate decommissioning costs associated with coal-fueled generating facilities and removal of Cholla Unit 4. In April 2020, PacifiCorp filed a stipulation with the WPSC resolving all issues addressed in PacifiCorp's depreciation rate study application with ratemaking treatment of certain matters to be addressed in PacifiCorp's general rate case, including depreciation for coal-fueled generating facilities and associated incremental decommissioning costs reflected in decommissioning studies and certain matters related to the repowering of PacifiCorp's wind-powered generating facilities. The stipulation was approved by the WPSC during a hearing in August 2020 and a subsequent written order in December 2020. The general rate case hearing was rescheduled for February 2021. As a result of the hearing date change, PacifiCorp filed an application in October 2020 with the WPSC requesting authorization to defer costs associated with impacts of the depreciation study. A hearing for this deferral application was held in July 2021. In September 2021, the WPSC approved in a bench decision PacifiCorp's application to defer depreciation expense incurred from January 1, 2021 through June 30, 2021 subject to certain offsetting cost savings during the relevant period. A final order is pending. The WPSC will address recovery of the deferred costs in a future general rate case.

In March 2020, PacifiCorp filed a general rate case with the WPSC which reflected recovery of Energy Vision 2020 investments, updated depreciation rates, incremental decommissioning costs associated with coal-fueled facilities and rate design modernization proposals. The application also requested a revision to the ECAM to eliminate the sharing band and requested authorization to discontinue operations and recover costs associated with the early retirement of Cholla Unit 4. The proposed increase reflects several rate mitigation measures that include use of the remaining 2017 Tax Reform benefits to buy down plant balances, including Cholla Unit 4, and spreading the recovery of the depreciation of certain coal-fueled generation units over time periods that extend beyond the depreciable lives proposed in the depreciation rate study. In September 2020, PacifiCorp filed its rebuttal testimony that modified its requested increase in base rates from $7 million to $9 million, or 1.3%, and reflected an update to the rate mitigation measures for using 2017 Tax Reform benefits. The WPSC determined that the rebuttal testimony filed constituted a material and substantial change to the original application and vacated the hearing that was scheduled for October 2020. The WPSC re-noticed PacifiCorp's case and rescheduled the hearings. The hearings began February 2021 and were completed in March 2021. In May 2021, the WPSC approved a $7 million base revenue requirement increase that includes the Energy Vision 2020 investments, updated depreciation rates, incremental decommissioning costs and rate design proposals to be offset by returning the remaining 2017 Tax Reform benefits to customers over the next three years. The WPSC also approved revisions to the ECAM to adjust the sharing band from 70/30 to 80/20 and to include PTCs within the mechanism. PacifiCorp's proposals for extended recovery of the depreciation of certain coal-fueled generation units and use of remaining 2017 Tax Reform benefits to buy down certain plant balances were denied. The WPSC decision resulted in an overall net decrease of 3.5% effective July 1, 2021. A final written order was issued in July 2021.

In April 2021, PacifiCorp filed its annual ECAM and REC and Sulfur Dioxide Revenue Adjustment Mechanism application with the WPSC requesting to refund $15 million of deferred net power costs and RECs to customers for the period January 1, 2020 through December 31, 2020, reflecting the difference between base and actual net power costs in the 2020 deferral period. This reflects a 2.4% decrease compared to current rates. PacifiCorp requested an interim rate effective July 1, 2021, which was approved by the WPSC in June 2021. PacifiCorp filed an all-party stipulation in October 2021. A hearing on the stipulation was held in November 2021 during which the WPSC approved the all-party stipulation in a bench decision and the final order was issued in February 2022.

Washington

In June 2021, PacifiCorp filed a power cost only rate case to update baseline net power costs for 2022. The proposed $13 million, or 3.7%, rate increase had a requested effective date of January 1, 2022. In November 2021, PacifiCorp reached a proposed settlement with most of the parties, which includes an agreement to adjust the PTC rate in base rates and apply a production factor and to include a net power cost update as part of the compliance filing. A hearing was held in January 2022 and a WUTC decision is pending.

Idaho

In March 2021, PacifiCorp filed its annual ECAM application with the IPUC requesting recovery of $14 million for deferred costs in 2020, a 1.1% decrease compared to current rates. This filing includes recovery of the difference in actual net power costs to the base level in rates, an adder for recovery of the Lake Side 2 resource, changes in PTCs, changes in RECs, and a resource tracking mechanism to match costs with the benefits of new wind and wind repowering projects until they are reflected in base rates. In May 2021, PacifiCorp updated the requested recovery to correct for certain load related data reflected in the initial application, and the IPUC approved recovery of $10 million for deferred costs, a 2.5% decrease compared to current rates, effective June 1, 2021.

In May 2021, PacifiCorp filed a general rate case with the IPUC requesting a $19 million, or 7.0%, revenue requirement increase effective January 1, 2022. This is the first general rate case PacifiCorp has filed in Idaho since 2011. The rate case includes recovery of Energy Vision 2020 investments, the Pryor Mountain wind-powered generating facility, repowered Foote Creek, new investment in transmission, updated depreciation rates, incremental decommissioning costs associated with coal-fueled facilities and rate design modernization proposals. The application also requested recovery of the decommissioning and closure costs associated with the early retirement of Cholla Unit 4. PacifiCorp filed an all-party settlement with the IPUC in October 2021, resolving all issues in the case. The settlement provides an $8 million, or 2.9%, overall increase, which will be offset in part by a refund of deferred income tax savings over two years, resulting in a net increase of $4 million, or 1.4%. In December 2021, the IPUC issued an order approving the settlement with rates effective January 1, 2022.

California

California SB 901 requires electric utilities to prepare and submit wildfire mitigation plans that describe the utilities' plans to prevent, combat and respond to wildfires affecting their service territories. PacifiCorp submitted its 2021 California Wildfire Mitigation Plan Update in March 2021 for which it received approval in July 2021.

In August 2020, PacifiCorp filed an application with the CPUC to address California energy costs and GHG allowance costs. The application includes a $7 million, or 6.7%, decrease in energy costs, which is largely attributed to PTCs for new and repowered Energy Vision 2020 resources, and an increase of $1 million, or 0.8%, to recover costs for purchasing GHG allowances as required by the state's Cap-and-Trade program. In March 2021, the CPUC approved the rate change related to GHG allowances and in November 2021, approved updated rates for energy costs as filed.

In August 2021, PacifiCorp filed an application with the CPUC to address California energy costs and GHG allowance costs. The application included a $5 million rate decrease associated with lower energy costs, partially offset by an increase of $3 million to recover costs for purchasing GHG allowances as required by the state's Cap-and-Trade program. PacifiCorp's application would result in a rate decrease of $2 million, or 1.9%, effective January 1, 2022. In January 2022, PacifiCorp filed an amended application, per CPUC direction, to reflect ECAC rates which had been approved since the original filing was made in August 2021. The amended application included an over $3 million rate increase associated with higher energy costs, as well as the previously sought increase of $3 million to recover GHG allowances. PacifiCorp's application would result in a rate increase of $7 million, or 6.6%. PacifiCorp anticipates interim approval of its GHG rates in March 2022 based on a settlement stipulation filed by the parties.

FERC Show Cause Order

On April 15, 2021, the FERC issued an order to show cause and notice of proposed penalty related to allegations made by FERC Office of Enforcement staff that PacifiCorp failed to comply with certain NERC reliability standards associated with facility ratings on PacifiCorp's bulk electric system. The order directs PacifiCorp to show cause as to why it should not be assessed a civil penalty of $42 million as a result of the alleged violations. The allegations are related to PacifiCorp's response to a 2010 industry-wide effort directed by the NERC to identify and remediate certain discrepancies resulting from transmission facility design and actual field conditions, including transmission line clearances. In July 2021, PacifiCorp filed its answer to the FERC's show cause order denying the alleged violation of certain NERC reliability standards. The FERC Office of Enforcement staff replied in September 2021. A decision by the FERC is pending.

MidAmerican Energy

Wind PRIME

In January 2022, MidAmerican Energy filed an application with the IUB for advance ratemaking principles for Wind PRIME. If approved, MidAmerican Energy expects to proceed with Wind PRIME, which consists of up to 2,042 MWs of new wind generation and up to 50 MWs of solar generation. If all of 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 secured sufficient safe harbor equipment necessary to remain eligible for 60% PTCs under current tax law and has asked the IUB to issue a final decision on the application by October 2022 to allow MidAmerican Energy to construct Wind PRIME and place it in-service by the end of 2024.

Natural Gas Purchased for Resale

In February 2021, severe cold weather over the central United States caused disruptions in natural gas supply from the southern part of the United States. These disruptions, combined with increased demand, resulted in historically high prices for natural gas purchased for resale to MidAmerican Energy's retail customers and caused an approximate $245 million increase in natural gas costs above those normally expected. To mitigate the impact to customers, the IUB ordered the recovery of these higher costs to be applied to customer bills over the period April 2021 through April 2022 based on a customer's monthly natural gas usage. While sufficient liquidity is available to MidAmerican Energy, the increased costs and longer recovery period resulted in higher working capital requirements during the year ended December 31, 2021.

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 ensures MidAmerican Energy, as an incumbent electric transmission owner, has the legal right to construct, own and maintain transmission lines that have been approved by the MISO (or another federally registered planning authority) in MidAmerican Energy's service territory. To exercise the legal right, MidAmerican Energy must notify the IUB within 90 days of any such approval for construction that it intends to construct, own and maintain the electric transmission line. 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 electric transmission line and, until the construction is complete, a quarterly report updating the estimated cost to construct the electric transmission line. Legal challenges have been brought against similar laws in other states, but courts that have ruled on such cases have upheld the states' laws. In October 2020, a lawsuit challenging the law was filed in Iowa by national transmission interests. The suit raises issues specific to Iowa law, and the State of Iowa is defending the law in the suit. MidAmerican Energy intervened in the suit and defended the law as well. The Iowa district court dismissed the lawsuit in March 2021, and the national transmission interests appealed. The parties are in the process of briefing the court. A date for oral arguments has not been set and is not expected until third quarter 2022.

Renewable Subscription Program

In December 2020, MidAmerican Energy filed with the IUB a proposed Renewable Subscription Program ("RSP") tariff. As proposed, the program would provide qualified industrial customers with the opportunity to meet their future energy growth above baseline levels with renewable energy from specific additions to MidAmerican Energy wind-powered generation and 100 MWs of planned solar generation for 20 years at fixed prices based on the cost of such facilities. Under the RSP, MidAmerican Energy would own the facilities, retain PTCs and other tax benefits associated with the facilities and include all revenues and costs from the program in its Iowa-jurisdictional results of operation, but renewable attributes from the facilities would be specifically assigned to subscribing customers. In June 2021, the IUB issued an order rejecting the RSP and, in July 2021, issued an order denying MidAmerican Energy's request for reconsideration thereof and affirming its June 2021 order. In the July order, the IUB expressed its view that the RSP-related generating facilities and associated PTCs, costs and revenues must be removed from MidAmerican Energy's revenue sharing calculations. In June 2021, the IUB issued an order opening a docket to review MidAmerican Energy's revenue sharing calculations. That docket remains open.

NV Energy (Nevada Power and Sierra Pacific)

Regulatory Rate Reviews

In June 2020, Nevada Power filed an electric regulatory rate review with the PUCN. The filing supported an annual revenue reduction of $96 million but requested an annual revenue reduction of $120 million. In September 2020, Nevada Power filed an all-party settlement for the electric regulatory rate review. The settlement resolved all but one issue and provided for an annual revenue reduction of $93 million and required Nevada Power to issue a $120 million one-time bill credit, composed primarily of existing regulatory liabilities, to customers beginning in October 2020. The continuation of the earning sharing mechanism was the one issue that was not addressed in the settlement. In October 2020, the PUCN held a hearing on the continuation of the earning sharing mechanism and issued an interim order accepting the settlement and requiring the one-time bill credit be issued to customers. The $120 million one-time bill credit was issued to customers in the fourth quarter of 2020. In December 2020, the PUCN issued a final order directing Nevada Power to continue the earning sharing mechanism subject to any modifications made to the earning sharing mechanism pursuant to an alternative ratemaking ruling and to use the weather normalization methodology adopted for Sierra Pacific in its 2019 regulatory rate review. The new rates were effective on January 1, 2021.

Price Stability Tariff

In November 2018, the Nevada Utilities made filings with the PUCN to implement the Customer Price Stability Tariff ("CPST"). The Nevada Utilities have designed the CPST to provide certain customers, namely those eligible to file an application pursuant to Chapter 704B of the Nevada Revised Statutes, with a market-based pricing option for renewable resources. The CPST provides for an energy rate that would replace the BTER and DEAA. The goal is to have an energy rate that yields an all-in effective rate that is competitive with market options available to such customers. In February 2019, the PUCN granted several intervenors the ability to participate in the proceeding. In June 2019, the Nevada Utilities withdrew their filings. In May 2020, the Nevada Utilities refiled the CPST incorporating the considerations raised by the PUCN and other intervenors and a hearing was held in September 2020. In November 2020, the PUCN issued an order approving the tariff with modified pricing and directing the Nevada Utilities to develop a methodology by which all eligible participants may have the opportunity to participate in the CPST program up to a limit with the same proportion of governmental entities' and non-governmental entities' MWh reserved for potentially interested customers as filed. In December 2020, the Nevada Utilities filed a petition for reconsideration of the pricing ordered by the PUCN. In January 2021, the PUCN issued an order reaffirming its order from November 2020 and denying the petition for a rehearing. In the first quarter of 2021, the Nevada Utilities filed an update to the CPST program per the November 2020 order and an updated CPST with the PUCN. The enrollment period for the tariff has ended with no customers having enrolled.

Natural Disaster Protection Plan

The Nevada Utilities submitted their initial NDPP to the PUCN and filed their first application seeking recovery of 2019 expenditures in February 2020. In June 2020, a hearing was held and an order was issued in August 2020 that granted the joint application, made adjustments to the budget and approved the 2019 costs for recovery starting in October 2020. In October 2020, intervening parties filed petitions for reconsideration. The Bureau of Consumer Protection filed a petition for judicial review with the district court in November 2020. In December 2020, the PUCN issued a second modified final order approving the NDPP, as modified, and reopened its investigation and rulemaking on SB 329 to address rate design issues raised by intervenors. The comment period for the reopened investigation and rulemaking ended in early February 2021 and an order is expected in 2022. In March 2021, the Nevada Utilities filed an application seeking recovery of the 2020 expenditures, approval for an update to the initial NDPP that was ordered by the PUCN and filed their first amendment to the 2020 NDPP. A hearing related to the application for approval of the first amendment to the 2020 NDPP was held in June 2021. The Nevada Utilities filed a partial-party stipulation resolving all issues. One of the intervening parties filed an opposition to the partial-party stipulation and other intervenors filed legal briefs. The partial-party stipulation was approved by the PUCN in June 2021 with the lone dissenting party retaining the right to argue a single issue in future proceedings with the primary issue being a single statewide rate as a cost recovery mechanism. In July 2021, a hearing was held on the cost recovery of 2020 expenditures. In September 2021, the PUCN issued an order, approving the recovery of the 2020 expenditures with adjustments for vegetation management, inspections and corrections and rate structure. Certain vegetation management expenditures were to be removed from the NDPP rate and deemed to be recovered through the general three-year regulatory rate review process. A portion of the inspections and corrections were deferred to seek recovery in a future NDPP rate filing. Lastly, the order approved cost recovery based on a hybrid rate calculation comprised of a statewide rate component for operating costs and a service territory specific rate component for capital costs. In September 2021, the Nevada Utilities and one of the intervening parties filed petitions for reconsideration that were granted by the PUCN. In January 2022, the PUCN issued an order reaffirming its order from September 2021.

SB 448

SB 448 was signed into law on June 10, 2021. The legislation is intended to accelerate transmission development, renewable energy and storage, and accelerate transportation electrification within the state of Nevada. In September 2021, the Nevada Utilities filed an amendment to the 2021 Joint IRP for the approval of their Transmission Infrastructure for a Clean Energy Economy Plan that sets forth a plan for the construction of high-voltage transmission infrastructure, Greenlink North among others, that will be placed into service no later than December 31, 2028, and requires the IRP to include at least one scenario that uses sources of supply that will achieve certain reductions in carbon dioxide emissions. In September 2021, the Nevada Utilities filed an application for the approval of their Economic Recovery Transportation Electrification Plan to accelerate transportation electrification in the state of Nevada. The plan establishes requirements for the contents of the transportation electrification investment as well as requirements for review, cost recovery and monitoring. The plan covers an initial period beginning January 1, 2022 and ending on December 31, 2024. In November 2021, the PUCN issued an order granting the application and accepting the Economic Recovery Transportation Electrification Plan with some modifications. The PUCN opened rulemakings to address other regulations that resulted from SB 448. These rulemakings are ongoing.

ON Line Temporary Rider ("ONTR")

In October 2021, Sierra Pacific filed an application with the PUCN for approval of the ONTR with corresponding updates to its electric rate tariffs to authorize recovery of the One Nevada Transmission Line ("ON Line") regulatory asset being accumulated as a result of the ON Line cost reallocation as well as the related on-going reallocated revenue requirement. Sierra Pacific's application would, if approved by the PUCN as filed, result in a one-time rate increase of $28 million to be collected over a nine-month period starting on April 1, 2022. In November 2021, intervening parties filed motions to dismiss the filing which were denied by the PUCN in December 2021. A hearing with the PUCN for the application was held in February 2022 and an order is expected in the first quarter of 2022.

Northern Powergrid Distribution Companies

GEMA, through the Ofgem is undertaking its scheduled review of the electricity distribution price control, to put in place a new price control at the end of the current period, which ends March 2023.

The new price control ("ED2") will run for five years, from April 2023 to March 2028. In December 2020 and March 2021, GEMA published its decision on the methodology it will use to set ED2. This confirmed that Ofgem will maintain many aspects of the current price control and that the changes being made will 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 some new service standard incentives and mechanisms to adjust cost allowances in specific circumstances, while others will be discontinued, and partially updating the allowed return on equity within the period for changes in the interest rate on government bonds.

Ofgem published a working assumption of 4.65% for the allowed cost of equity (plus inflation calculated using the United Kingdom's consumer prices index including owner occupiers' housing costs, CPIH). When placed on a comparable footing, by adjusting for differences in the assumed equity ratio and the measure of inflation used, this working assumption is approximately two percentage points lower than the current cost of equity for electricity distribution. Ofgem will set a final value in its determinations in late 2022.

In December 2021, Northern Powergrid published and filed its business plan with Ofgem, setting out its detailed approach for 2023-2028 including the cost allowances this approach would require. Ofgem is expected to publish draft determinations of the new price control in mid-2022 with final determinations expected in late 2022.

BHE Pipeline Group

BHE GT&S

In September 2021, EGTS filed a general rate case for its FERC-jurisdictional services, with proposed rates to be effective November 1, 2021. EGTS' previous general rate case was settled in 1998. 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 transportation 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 and the outcome of hearing procedures. This matter is pending.

In January 2020, pursuant to the terms of a previous settlement, Cove Point filed a general rate case for its FERC-jurisdictional services, with proposed rates to be effective March 1, 2020. Cove Point proposed an annual cost-of-service of approximately $182 million. In February 2020, the FERC approved suspending the changes in rates for five months following the proposed effective date, until August 1, 2020, subject to refund. In November 2020, Cove Point reached an agreement in principle with the active participants in the general rate case proceeding. Under the terms of the agreement in principle, Cove Point's rates effective August 1, 2020 result in an increase to annual revenues of approximately $4 million and a decrease in annual depreciation expense of approximately $1 million, compared to the rates in effect prior to August 1, 2020. The interim settlement rates were implemented November 1, 2020, and Cove Point's provision for rate refunds for August 2020 through October 2020 totaled $7 million. The agreement in principle was reflected in a stipulation and agreement filed with the FERC in January 2021. In March 2021, the FERC approved the stipulation and agreement and the rate refunds to customers were processed in late April 2021.

Northern Natural Gas

In January 2019, FERC initiated a Section 5 investigation to determine whether the rates currently charged by Northern Natural Gas are just and reasonable. As required by the FERC Section 5 order, Northern Natural Gas filed a cost and revenue study in April 2019. In July 2019, Northern Natural Gas filed a Section 4 rate case requesting increases in its transportation and storage rates. In January 2020, the FERC approved Northern Natural Gas' filing to implement its interim rates subject to refund, effective January 1, 2020. In June 2020, a settlement agreement was filed with the FERC, resolving the Section 5 investigation and Section 4 rate case and providing for increased service rates and depreciation rates. Market Area transportation reservation rates increased 28.5% and storage reservation rates increased 67.0% from the rates that were in effect in 2019. Depreciation rates are 2.3% for onshore transmission plant, 2.95% for LNG storage plant, 13.0% for intangible plant, and 2.75% for general plant. The settlement also provides for a Section 4 and Section 5 rate action moratorium through June 30, 2022, subject to certain exceptions, as well as provides for minimum annual maintenance capital spending. The settlement rates were implemented May 1, 2020, and the Company's provision for rate refunds for January 2020 through April 2020 totaled $69 million. The FERC approved the settlement in September 2020, and rate refunds to customers were processed in early October 2020.

BHE Transmission

AltaLink

Tariff Refund Application

In January 2021, driven by the pandemic and economic shutdown that negatively impacted all Albertans, AltaLink filed an application with the AUC that requested approval of tariff relief measures totaling C$350 million over the three-year period, 2021 to 2023. The tariff relief measures consisted of a proposed refund to customers of C$150 million of previously collected future income taxes and C$200 million of surplus accumulated depreciation.

In March 2021, the AUC issued a decision on AltaLink's Tariff Refund Application and approved a 2021 customer tariff refund in the amount of C$230 million and a net 2021 tariff reduction of C$224 million, which provided Alberta customers with immediate tariff relief in 2021. The approved 2021 tariff refund included a refund of C$150 million of previously collected future income tax and a refund of C$80 million of accumulated depreciation surplus. Tariff relief measures for years 2022 and 2023 were proposed in AltaLink's 2022-2023 GTA.

2019-2021 General Tariff Application

In August 2018, AltaLink filed its 2019-2021 GTA with the AUC, delivering on the first three years of its commitment to keep rates lower or flat at the approved 2018 revenue requirement of C$904 million for customers for the next five years. In addition, AltaLink proposed to provide a further tariff reduction over the three-year period by refunding previously collected accumulated depreciation surplus of an additional C$31 million. In April 2019, AltaLink filed an update to its 2019-2021 GTA primarily to reflect its 2018 actual results and the impact of the AUC's decision on AltaLink's 2014-2015 Deferral Accounts Reconciliation Application. The application requested the approval of revised revenue requirements of C$879 million, C$882 million and C$885 million for 2019, 2020 and 2021, respectively.

In July 2019, AltaLink filed a 2019-2021 partial negotiated settlement application with the AUC. The application consisted of negotiated reductions that resulted in a net decrease of C$38 million to the three-year total revenue requirement applied for in AltaLink's 2019-2021 GTA updated in April 2019. However, this was offset by AltaLink's request for an additional C$20 million of forecast transmission line clearance capital as part of an excluded matter. The 2019-2021 negotiated settlement agreement excluded certain matters related to the new salvage study and salvage recovery approach, additional capital spending and incremental asset retirements. AltaLink's salvage proposal is estimated to save customers C$267 million between 2019 and 2023.

In April 2020, the AUC issued its decision with respect to AltaLink's 2019-2021 GTA. The AUC approved the negotiated settlement agreement as filed and rendered its decision and directions on the excluded matters. The AUC declined to approve AltaLink's proposed salvage methodology at that time but indicated it would initiate a generic proceeding to review the matter on an industry-wide basis. The AUC approved, on a placeholder basis, C$13 million of the additional C$20 million AltaLink requested for forecast transmission line clearance capital. The remaining C$7 million of capital investment was reviewed in AltaLink's subsequent compliance filing. Also, C$3 million of forecast operating expenses and C$4 million of forecast capital expenditures related to fire risk mitigation were approved, with an additional C$31 million of capital expenditures reviewed in the compliance filing. Finally, the AUC approved C$6 million of retirements for towers and fixtures.

In July 2020, the AUC approved AltaLink's compliance filing establishing revised revenue requirements of C$895 million for 2019, C$894 million for 2020 and C$898 million for 2021, exclusive of the assets transferred to the PiikaniLink Limited Partnership and the KainaiLink Limited Partnership. The AUC deferred its decision on AltaLink's proposed salvage methodology included in AltaLink's 2019-2021 GTA, pending a generic proceeding to consider the broader implications. This generic proceeding was closed and in July 2020, AltaLink filed an application with the AUC for the review and variance of the AUC's decision with respect to AltaLink's proposed salvage methodology. In September 2020, the AUC granted this review on the basis that there were changed circumstances that could lead the AUC to materially vary or rescind the majority hearing panel's findings on AltaLink's proposed salvage methodology. In November 2020, the AUC issued its decision on AltaLink's review and variance application. The AUC decided to vary the original decision and approve AltaLink's proposed net salvage method and the revised transmission tariffs as filed, effective December 2020. The new salvage methodology decreased the amount of salvage pre-collection resulting in reductions to AltaLink's revenue requirement from customers by C$24 million, C$27 million and C$31 million for the years 2019, 2020 and 2021, respectively. AltaLink delivered on the first three years of its commitment to customers to keep rates flat for five years by obtaining the necessary AUC approvals. AltaLink's approved 2019-2021 GTA maintains customer rates below the 2018 level of C$904 million from 2019 to 2021.

In March 2021, the AUC approved AltaLink's Tariff Refund Application resulting in a revised revenue requirement of C$873 million and revised transmission tariff of C$633 million for 2021.

2022-2023 General Tariff Application

In April 2021, AltaLink filed its 2022-2023 GTA delivering on the last two years of its commitment to keep rates flat for customers at or below the 2018 level of C$904 million for the five-year period from 2019 to 2023. The two-year application achieves flat tariffs by continuing to transition to the AUC-approved salvage recovery method and continuing the use of the flow-through income tax method, with an overall year-over-year increase of approximately 2% in 2022 and 2023 revenue requirements. In addition, similar to the C$80 million refund of the previously collected accumulated depreciation surplus approved by the AUC for 2021, AltaLink proposed to provide further similar tariff reductions over the two years by refunding an additional C$60 million per year. The application requested the approval of transmission tariffs of C$824 million and C$847 million for 2022 and 2023, respectively.

In September 2021, AltaLink provided responses to information requests from the AUC and filed an amended application to reflect certain adjustments and forecast updates. The amended application requested the approval of transmission tariffs of C$820 million and C$843 million for 2022 and 2023, respectively. In November 2021, the AUC approved the 2022 interim refundable transmission tariff at C$57 million per month effective January 2022.

In January 2022, the AUC issued its decision with respect to AltaLink's 2022-2023 GTA. The AUC approved a two-year total revenue requirement of C$1.7 billion as compared to AltaLink's requested revenue requirement of C$1.8 billion. AltaLink's 2022-2023 GTA reflected its continued commitment to provide rate stability to customers by maintaining flat tariffs and providing additional tariff relief measures, including a proposed tariff refund of C$60 million of accumulated depreciation in each of 2022 and 2023. The AUC did not approve AltaLink's proposed refund due to an anticipated improvement in general economic conditions in Alberta.

2022 Generic Cost of Capital Proceeding

In December 2020, the AUC initiated the 2022 generic cost of capital proceeding. This proceeding considered the return on equity and deemed equity ratios for 2022 and one or more additional test years. Due to the uncertainty as a result of the ongoing COVID-19 pandemic, before establishing a process schedule, the AUC requested participants to submit comments that addressed the following: (i) the continuation of the currently approved return on equity and deemed equity ratios for a further period of time; (ii) the appropriate test period for the proceeding; (iii) the scope of the proceeding, including whether a formula-based approach to return on equity should be utilized; (iv) the considerations to take into account when establishing the process for the proceeding; and (v) the avoidance of duplicative evidence and greater coordination and collaboration between parties.

In January 2021, AltaLink submitted a letter to the AUC stating that due to ongoing capital market volatility and other COVID-19 related uncertainties there are reasonable grounds for extending the currently approved 2021 return on equity and deemed equity ratio on a final basis for 2022. AltaLink further stated there was insufficient time to complete a full generic cost of capital proceeding in 2021, in order to issue a decision prior to the beginning of 2022 and a formula-based approach should not be considered at this time. AltaLink suggested that a proceeding could be restarted in the third quarter of 2021, for 2023 and subsequent years.

In March 2021, the AUC issued its decision with respect to setting the return on equity and deemed equity ratios for AltaLink. The AUC approved an equity return of 8.5% and an equity ratio of 37% for 2022, based on continuing economic and market uncertainties, the unsettled nature of capital markets, and the need for certainty and stability for Alberta customers.

2023 Generic Cost of Capital Proceeding

In January 2022, the AUC initiated the 2023 generic cost of capital proceeding. The proceeding will be conducted in two stages. The first stage will determine the cost of capital parameters for 2023 and the second stage will consider returning to a formula-based approach to establish cost of capital adjustments, commencing in 2024. Due to ongoing capital market uncertainties related to COVID-19, the AUC is considering extending the 2022 approved cost of capital parameters, of 8.5% return on equity and 37% deemed equity ratio, to 2023. The AUC intends to issue a decision on the first stage by March 31, 2022. With respect to the second stage, the AUC plans to commence the 2024 GCOC proceeding to establish a formula-based approach in the third quarter of 2022 and to conclude in the second quarter of 2023.

2019 Deferral Accounts Reconciliation Application

In October 2020, AltaLink filed its application with the AUC, which included 10 projects with total gross capital additions of C$129 million, including applicable AFUDC. In March 2021, the AUC issued its decision on AltaLink's 2019 Deferral Accounts Reconciliation Application. The AUC approved C$128 million of the gross capital project additions. The AUC also approved the other deferral accounts for taxes other than income taxes, long-term debt and annual structure payments as filed. AltaLink filed its compliance filing in April 2021. In May 2021, the AUC issued its decision approving the compliance filing as filed.

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, 2023. In January 2021, the Public Utilities Commission of Texas ("PUCT") approved ETT's request to suspend a base regulatory rate review filing scheduled for February 2021. 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 2017 Tax Reform 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 climate change, RPS, air and water quality, emissions performance standards, coal combustion byproduct disposal, hazardous and solid waste disposal, protected species 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 $30.1 billion and (ii) wind tax equity investments of $5.9 billion. The Company plans to spend an additional $7.8 billion on the construction of renewable generating facilities and repowering certain existing wind-powered generating facilities through 2024. 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.

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 United States 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. On June 1, 2017, President Trump announced the United States would begin the process of withdrawing from the Paris Agreement. The United States completed its withdrawal from the Paris Agreement on November 4, 2020. President Biden accepted the terms of the climate agreement January 20, 2021, and the United States completed its reentry February 19, 2021. At a Climate Leaders' Summit held in April 2021, President Biden announced new climate goals to cut GHG emissions 50%-52% economy-wide by 2030 compared to 2005 levels and to reach 100% carbon pollution-free electricity by 2035.

GHG Performance Standards

Under the Clean Air Act, the EPA may establish emissions standards that reflect the degree of emissions reductions achievable through the best technology that has been demonstrated, taking into consideration the cost of achieving those reductions and any non-air quality health and environmental impact and energy requirements. On August 3, 2015, the EPA issued final new source performance standards, establishing a standard of 1,000 pounds of carbon dioxide per MWh for large natural gas-fueled generating facilities and 1,400 pounds of carbon dioxide per MWh for new coal-fueled generating facilities with the "Best System of Emission Reduction" reflecting highly efficient supercritical pulverized coal facilities with partial carbon capture and sequestration or integrated gasification combined-cycle units that are co-fueled with natural gas or pre-combustion slipstream capture of carbon dioxide. The new source performance standards were appealed to the D.C. Circuit and oral argument was scheduled for April 17, 2017. However, oral argument was deferred, and the court held the case in abeyance for an indefinite period of time. On December 6, 2018, the EPA announced revisions to new source performance standards for new and reconstructed coal-fueled units. The EPA proposes to revise carbon dioxide emission limits for new coal-fueled facilities to 1,900 pounds per MWh for small units and 2,000 pounds per MWh for large units. The EPA would define the best system of emission reduction for new and modified units as the most efficient demonstrated steam cycle, combined with best operating practices. On January 12, 2021, the EPA finalized a rule focused solely on a significant contribution finding for purposes of regulating source categories' GHG emissions. The final rule sets no specific regulatory standards and contains no regulatory text, nor does it address what constitutes the best system of emission reduction for new, modified and reconstructed electric generating units. The EPA confirms in the "significant contribution" rule that electric generating units remain a listed source category under Clean Air Act Section 111(b), reaching that conclusion through the introduction of an emissions threshold framework by which a source category is deemed to contribute significantly to dangerous air pollution due to their GHG emissions if the amount of those emissions exceeds 3% of total GHG emissions in the United States. Under this methodology, no other source category would qualify for regulation. The significant contribution rule will take effect 60 days after publication in the *Federal Register* but is expected to be quickly revisited by the Biden administration. Because the significant contribution rule did not alter the emission limits or technology requirements of the 2015 rule, any new fossil-fueled generating facilities will be required to meet the GHG new source performance standards. The D.C. Circuit vacated the significant contribution rule on April 5, 2021.

Affordable Clean Energy Rule

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 United States Supreme Court in February 2016 while litigation proceeded. On October 10, 2017, the EPA issued a proposal to repeal the Clean Power Plan, which was intended to achieve an overall reduction in carbon dioxide emissions from existing fossil-fueled electric generating units of 32% below 2005 levels. On June 19, 2019, the EPA repealed the Clean Power Plan and issued the Affordable Clean Energy rule, which fully replaced the Clean Power Plan. In the Affordable Clean Energy rule, the EPA determined that the best system of emissions 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. States have until July 2022 to submit compliance plans to the EPA. 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 United States Supreme Court agreed to hear an appeal of that decision. Arguments in the case will be held February 28, 2022, and a decision regarding the scope of the EPA's authority to regulate greenhouse gas emissions under the Clean Air Act is expected by June 2022. Until litigation is exhausted and the EPA indicates its course of action in response to this decision, the full impacts on the Registrants cannot be determined. PacifiCorp, MidAmerican Energy, Nevada Power and Sierra Pacific have historically pursued cost-effective projects, including generating facility efficiency improvements, increased diversification of their generating fleets to include deployment of renewable and lower carbon generating resources, and advanced customer energy efficiency programs.

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 emissions 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 intends to issue a supplemental proposal in 2022, including draft regulatory text, and plans to finalize the rules by the end of 2022. Until the rules are finalized, the relevant Registrants cannot determine the full impacts of the proposed rule.

Regional and State Activities

Several states have promulgated or otherwise participate in state-specific or regional laws or initiatives to report or mitigate GHG emissions. These are expected to impact the relevant Registrant, and include:

- In June 2013, Nevada SB 123 was signed into law. Among other things, SB 123 and regulations thereunder required Nevada Power to file with the PUCN an emissions reduction and capacity replacement plan by May 1, 2014. In May 2014, Nevada Power filed its emissions reduction capacity replacement plan. The plan provided for the retirement or elimination of 300 MWs of coal-fueled generating capacity by December 31, 2014, another 250 MWs of coal-fueled generating capacity by December 31, 2017, and another 250 MWs of coal generating capacity by December 31, 2019, along with replacement of such capacity with a mixture of constructed, acquired or contracted renewable and non-technology specific generating units. The plan also sets forth the expected timeline and costs associated with decommissioning coal-fueled generating units that will be retired or eliminated pursuant to the plan. The PUCN has the authority to approve or modify the emission reduction and capacity replacement plan filed by Nevada Power. The PUCN may approve variations to Nevada Power's resource plans relative to requirements under SB 123. Refer to Nevada Power's Note 14 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information on the ERCR Plan.
- Under the authority of California's Global Warming Solutions Act, which includes a series of policies aimed at returning California GHG emissions to 1990 levels by 2020, the California Air Resources Board adopted a GHG cap-and-trade program with an effective date of January 1, 2012; compliance obligations were imposed on entities beginning in 2013. PacifiCorp is subject to the cap-and-trade program as a retail service provider in California and an importer of wholesale energy into California. In 2015, California's governor issued an executive order to reduce emissions to 40% below 1990 levels by 2030 and 80% by 2050. In September 2016, California SB 32 was signed into law establishing GHG emissions reduction targets of 40% below 1990 levels by 2030.
- The states of California, Washington and Oregon have adopted GHG emissions performance standards for base load electricity generating resources. Under the laws in California and Oregon, the emissions performance standards provide that emissions must not exceed 1,100 pounds of carbon dioxide per MWh. In September 2018, the Washington Department of Commerce amended the emissions performance standards to provide that GHG emissions for base load electricity generating resources must not exceed 925 pounds of carbon dioxide per MWh. These GHG emissions performance standards generally prohibit electric utilities from entering into long-term financial commitments (e.g., new ownership investments, upgrades, or new or renewed contracts with a term of five or more years) unless any base load generation supplied under long-term financial commitments comply with the GHG emissions performance standards.

- In September 2016, the Washington Department of Ecology issued a final rule regulating GHG emissions from sources in Washington. The rule regulates GHG including carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride beginning in 2017 with three-year compliance periods thereafter (i.e., 2017-2019, 2020-2022, etc.). Under the rule, the Washington Department of Ecology established GHG emissions reduction pathways for all covered entities. Covered entities may use emission reduction units, which may be traded with other covered entities, to meet their compliance requirements. PacifiCorp's resource that is covered under the rule includes the Chehalis generating facility, which is a natural gas combined-cycle generating facility located in Washington state. PacifiCorp received its baseline emission order on December 17, 2017, which specified the emission reduction requirements for the Chehalis generating facility every three years beginning in 2017. The reduction requirements average 1.7% per year. However, the Washington Department of Ecology suspended the compliance obligations of the Clean Air Rule after a Thurston County Superior Court judge ruled the state lacks authority to mandate reductions from indirect emitters. On January 16, 2020, the Washington Supreme Court affirmed that the rule limits the applicability of emission standards to actual emitters and cannot be expanded to non-emitters. The court also found that the rule itself is severable, so that the Washington Department of Ecology may continue to enforce the rule as it applies to emitters. The case was remanded for further proceedings. Pending further action by the lower court, the rule itself remains suspended, but entities subject to the rule are required to continue reporting emissions.
- The Regional Greenhouse Gas Initiative, a mandatory, market-based effort to cap and reduce power sector GHG emissions in 11 Eastern states, required, beginning in 2009, the reduction of carbon dioxide emissions from the power sector of 10% by 2018. Following a program review in 2012, the nine Regional Greenhouse Gas Initiative states implemented a new 2014 cap which was approximately 45% lower than the 2012-2013 cap. The cap is reduced each year by 2.5% from 2015 to 2020. In December 2017, an updated model rule was released by the Regional Greenhouse Gas Initiative states which includes an additional 30% regional cap reduction between 2020 and 2030.
- On May 7, 2019, Washington's governor signed into law the Clean Energy Transformation Act ("CETA") (SB 5116), which requires utilities to eliminate coal generation from Washington customers' allocation of electricity and requires all sales of electricity to Washington retail electric customers to be greenhouse gas neutral by 2030, and non-emitting and electric generation from renewable resources to supply 100% of retail sales by 2045. Electric utilities must also eliminate from rates coal-fueled resources by December 31, 2025. PacifiCorp submitted its first Clean Energy Implementation Plan, demonstrating how it plans to meet the targets established in the law, on December 30, 2021.
- On July 27, 2021, Oregon's governor signed House Bill 2021, which requires utilities to reduce GHG emissions to meet certain clean energy targets. The bill sets a baseline of the average of 2010, 2011 and 2012 emissions and requires utilities to meet the following reductions from that baseline: 80% by 2030, 90% by 2035 and 100% by 2040. The law also requires by 2030 at least 10% of the aggregate electrical capacity of utilities to be comprised of small-scale renewable resources with a capacity of 20 MWs or less by 2030. No earlier than second quarter 2023, PacifiCorp must file a clean energy plan with the OPUC showing how it will meet the clean energy targets. While the regulatory framework is still being developed, PacifiCorp anticipates coordinating the submittals of its clean energy plan and IRP in 2023.
- On May 17, 2021, the state of Washington passed the Climate Commitment Act (SB 5126), which creates an economy-wide cap-and-trade program to reduce GHG emissions. Under the Climate Commitment Act, the Washington Department of Ecology must establish progressively declining annual allowance budgets for emissions of GHG beginning January 1, 2023. PacifiCorp is subject to the Climate Commitment Act as an importer and generator of electricity in Washington.
- Illinois enacted the Climate and Equitable Jobs Act in September 2021, a wide-ranging energy omnibus bill touching on nearly all aspects of state energy policy. Among other things, the act codifies Illinois' policy to rapidly transition to 100% clean energy by 2050, which is achieved, in part, by preserving existing nuclear generation, doubling investment in wind and solar projects, and investigating alternative technologies, such as energy storage.
- Wisconsin, through a 2019 executive order, established the Wisconsin Office of Sustainability and Clean Energy, which is charged with achieving a goal of 100% carbon-free electricity by 2050. To assist reaching that goal, Wisconsin's governor also established the Governor's Task Force on Climate Change, to solicit stakeholder input and develop policy recommendations to meaningfully mitigate and adapt to the effects of climate change. Aggressive utility carbon reduction goals are among the task force's recommendations, including a goal of reducing net energy-sector carbon emissions to 100% below 2005 levels by 2050.

- Minnesota enacted an economy-wide requirement to reduce GHG emissions at least 80% below 2005 levels by 2050. The state codified a preference for using clean energy resources to meet its electricity demand, and that preference served as a basis for the state's largest utilities to commit to 100% carbon-free electricity by 2050. Minnesota's governor recently accelerated the state's timeline by proposing a standard requiring utilities to provide 100% carbon-free electricity by 2040, a decade earlier than current commitments. The accelerated standard is currently being considered by the state's legislature.

Renewable Portfolio Standards

Each state's RPS described below could significantly impact the relevant Registrant's consolidated financial results. Resources that meet the qualifying electricity requirements under each RPS vary from state to state. Each state's RPS requires some form of compliance reporting, and the relevant Registrant can be subject to penalties in the event of noncompliance. Each Registrant believes it is in material compliance with all applicable RPS laws and regulations.

In 1983, Iowa became the first state in the United States to adopt a RPS requiring the state utilities to own or to contract for a combined total of 105 MWs of renewable generating capacity and associated energy production. The IUB allocated the 105-MW requirement between the two utilities in Iowa based on each utility's percentage of their combined estimated Iowa retail peak demand in 1990 resulting in MidAmerican Energy being allocated a RPS requirement of 55.2 MWs. The utility must meet its RPS obligation by either owning renewable energy production facilities located in Iowa or entering into long-term contracts to purchase or wheel electricity from renewable production facilities located in the utility's service area.

Since 1997, NV Energy has been required to comply with a RPS. In November 2020, Nevada voters approved a constitution amendment that requires the state to obtain at least half its electricity from renewable sources by 2030. Beginning in 2022, the state must get 22% of its electricity from renewable sources. That percentage is increased incrementally over eight years up to the 50% threshold by 2030. The state's previous RPS required utilities to obtain 25% of their electricity from renewable sources by 2025.

Utah's Energy Resource and Carbon Emission Reduction Initiative provides that, beginning in the year 2025, 20% of adjusted retail electric sales of all Utah utilities be supplied by renewable energy, if it is cost effective. Retail electric sales will be adjusted by deducting the amount of generation from sources that produce zero or reduced carbon emissions, and for sales avoided as a result of energy efficiency and DSM programs. Qualifying renewable energy sources can be located anywhere within the WECC, and RECs can be used.

The Oregon Renewable Energy Act ("OREA") provides a comprehensive renewable energy policy and RPS for Oregon. Subject to certain exemptions and cost limitations established in the law, PacifiCorp and other qualifying electric utilities must meet minimum qualifying electricity requirements for electricity sold to retail customers of at least 5% in 2011 through 2014, 15% in 2015 through 2019, and 20% in 2020 through 2024. In March 2016, Oregon SB 1547-B, the Clean Electricity and Coal Transition Plan, was signed into law. SB 1547-B requires coal-fueled resources be eliminated from Oregon's allocation of electricity by January 1, 2030 and increases the current RPS target from 25% in 2025 to 50% by 2040. SB 1547-B also implements new REC banking provisions, as well as the following interim RPS targets: 27% in 2025 through 2029, 35% in 2030 through 2034, 45% in 2035 through 2039, and 50% by 2040 and subsequent years. As required by the OREA, the OPUC has approved an automatic adjustment clause (the RAC) to allow an electric utility, including PacifiCorp, to recover prudently incurred costs of its investments in renewable energy generating facilities and associated transmission costs.

Washington's Energy Independence Act establishes a renewable energy target for qualifying electric utilities, including PacifiCorp. The requirements are 3% of retail sales by January 1, 2012 through 2015, 9% of retail sales by January 1, 2016 through 2019 and 15% of retail sales by January 1, 2020 and each year thereafter. In April 2013, Washington SB 5400 was signed into law. SB 5400 expands the geographic area in which eligible renewable resources may be located to beyond the Pacific Northwest, allowing renewable resources located in all states served by PacifiCorp to qualify. SB 5400 also provides PacifiCorp with additional flexibility and options to meet Washington's renewable mandates. Washington's recently enacted CETA, among other things, requires Washington utilities to be carbon neutral by January 1, 2030 and institutes a planning target of 100% non-emitting generation by 2045. Electric utilities must also eliminate from rates coal-fueled resources by December 31, 2025.

The California RPS required all California retail sellers to procure an average of 20% of retail load from renewable resources by December 31, 2013, 25% by December 31, 2016 and 33% by December 31, 2020. In October 2015, California SB 350 became law and increased the RPS target to 50% by December 31, 2030. The state's RPS was further expanded in September 2018, when California SB 100, the 100 Percent Clean Energy Act of 2018 was signed into law. In addition to requiring retail sellers to meet a RPS target of 60% by 2030, SB 100 enabled a longer-term planning target for 100% of total California retail sales to come from eligible renewable energy resources and zero-carbon resources by December 31, 2045. In December 2011, the CPUC adopted a decision confirming that multi-jurisdictional utilities, such as PacifiCorp, are not subject to the percentage limits within the three product content categories of RPS-eligible resources established by the legislation that have been imposed on other California retail sellers.

Clean Air Act Regulations

The Clean Air Act is a federal law administered by the EPA that provides a framework for protecting and improving the nation's air quality and controlling sources of air emissions. The implementation of new standards is generally outlined in SIPs, which are a collection of regulations, programs and policies to be followed. SIPs vary by state and are subject to public hearings and EPA approval. Some states may adopt additional or more stringent requirements than those implemented by the EPA. The major Clean Air Act programs most directly affecting the Registrants' operations are described below.

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 United States. 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. The EPA must finalize the proposed rules by December 15, 2022. In addition, the EPA must, by December 15, 2022, approve or disapprove the interstate plans of Arizona, California, Nevada and Wyoming. Also in January 2022, the EPA initiated interagency review of a new rule to address "good neighbor" SIP provisions. While the interagency review is not yet complete and the proposed rule is not available for public comment, the EPA has indicated the action would apply in certain states for which the EPA has either disapproved a "good neighbor" SIP submission or has made a finding of failure to submit such a plan for the 2015 ozone NAAQS. The action would determine whether and to what extent ozone-precursor emissions reductions are required to eliminate significant contribution or interference with maintenance from upwind states that are linked to air quality problems in other states for the 2015 standard. Until the EPA takes final action consistent with this decree, impacts to the relevant Registrants cannot be determined.

In January 2010, the EPA finalized a one-hour air quality standard for nitrogen dioxide at 100 parts per billion. In February 2012, the EPA published final designations indicating that based on air quality monitoring data, all areas of the country are designated as "unclassifiable/attainment" for the 2010 nitrogen dioxide NAAQS. On April 6, 2018, the EPA issued a decision to retain the 2010 nitrogen dioxide NAAQS without revision.

In June 2010, the EPA finalized a new NAAQS for SO_2. Under the 2010 rule, areas must meet a one-hour standard of 75 parts per billion utilizing a three-year average. The rule utilizes source modeling in addition to the installation of ambient monitors where SO_2 emissions impact populated areas. Attainment designations were due by June 2012; however, citing a lack of sufficient information to make the designations, the EPA did not issue its final designations until July 2013 and determined, at that date, that a portion of Muscatine County, Iowa was in nonattainment for the one-hour SO_2 standard. MidAmerican Energy's Louisa coal-fueled generating facility is located just outside of Muscatine County, south of the violating monitor. In its final designation, the EPA indicated that it was not yet prepared to conclude that the emissions from the Louisa coal-fueled generating facility contribute to the monitored violation or to other possible violations, and that in a subsequent round of designations, the EPA will make decisions for areas and sources outside Muscatine County. MidAmerican Energy does not believe a subsequent nonattainment designation will have a material impact on the Louisa coal-fueled generating facility. Although the EPA's July 2013 designations did not impact PacifiCorp's nor the Nevada Utilities' generating facilities, the EPA's assessment of SO_2 area designations will continue with the deployment of additional SO_2 monitoring networks across the country. On February 25, 2019, the EPA issued a decision to retain the 2010 SO_2 NAAQS without revision.

The Sierra Club filed a lawsuit against the EPA in August 2013 with respect to the one-hour SO_2 standards and its failure to make certain attainment designations in a timely manner. In March 2015, the United States District Court for the Northern District of California ("Northern District of California") accepted as an enforceable order an agreement between the EPA and Sierra Club to resolve litigation concerning the deadline for completing the designations. The Northern District of California's order directed the EPA to complete designations in three phases: the first phase by July 2, 2016; the second phase by December 31, 2017; and the final phase by December 31, 2020. The first phase of the designations required the EPA to designate two groups of areas: 1) areas that have newly monitored violations of the 2010 SO_2 standard; and 2) areas that contain any stationary source that, according to the EPA's data, either emitted more than 16,000 tons of SO_2 in 2012 or emitted more than 2,600 tons of SO_2 and had an emission rate of at least 0.45 lbs/SO_2 per million British thermal unit in 2012 and, as of March 2, 2015, had not been announced for retirement. MidAmerican Energy's George Neal Unit 4 and the Ottumwa Generating Station (in which MidAmerican Energy has a majority ownership interest, but does not operate) are included as units subject to the first phase of the designations, having emitted more than 2,600 tons of SO_2 and having an emission rate of at least 0.45 lbs/SO_2 per million British thermal unit in 2012. States may submit to the EPA updated recommendations and supporting information for the EPA to consider in making its determinations. Iowa submitted documentation to the EPA in April 2016 supporting its recommendation that Des Moines, Wapello and Woodbury Counties be designated as being in attainment of the standard. In July 2016, the EPA's final designations were published in the *Federal Register* indicating portions of Muscatine County, Iowa were in nonattainment with the 2010 SO_2 standard, Woodbury County, Iowa was unclassifiable, and Des Moines and Wapello Counties were unclassifiable/attainment. On March 26, 2021, the EPA issued the last of its final designations for the 2010 primary SO_2 standard. Included in this round was designation of Converse County, Wyoming as an Attainment/Unclassifiable area. PacifiCorp's Dave Johnston generating facility is located in Converse County. No further action by PacifiCorp is required.

In December 2012, the EPA finalized more stringent fine particulate matter NAAQS, reducing the annual standard from 15 micrograms per cubic meter to 12 micrograms per cubic meter and retaining the 24-hour standard at 35 micrograms per cubic meter. The EPA did not set a separate secondary visibility standard, choosing to rely on the existing secondary 24-hour standard to protect against visibility impairment. In December 2014, the EPA issued final area designations for the 2012 fine particulate matter standard. Based on these designations, the areas in which the relevant Registrant operates generating facilities have been classified as "unclassifiable/attainment." Unless additional monitoring suggests otherwise, the relevant Registrant does not anticipate that any impacts of the revised standard will be significant. In December 2020, the EPA finalized its decision to retain, without revision, the existing primary and secondary standards for particulate matter. In June 2020, the EPA proposed a determination of attainment for the 2006 24-hour fine particulate matter for Salt Lake City and Provo, Utah, serious nonattainment areas. The determination is based upon quality-assured, quality controlled and certified ambient air monitoring data showing that the area has attained the 2006 standard based on the 2017-2019 monitoring. The comment period for the proposal ended in August 2020. In October 2021, the EPA issued a draft policy assessment for reconsideration on the 2020 particulate matter determination and accepted comments through December 2021. Until the rule and its reconsideration are finalized, the relevant Registrants cannot determine the impact on their operations.

In December 2014, the Utah SIP for fine particulate matter was adopted by the Utah Air Quality Board. PacifiCorp's Lake Side, Lake Side 2, Gadsby Steam and Gadsby Peakers generating facilities operate within nonattainment areas for fine particulate matter; however, the SIP did not impose significant new requirements on PacifiCorp's impacted generating facilities, nor did the EPA's comments on the Utah SIP identify requirements for PacifiCorp's existing generating facilities that would have a material impact on its consolidated financial results.

Mercury and Air Toxics Standards

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

MidAmerican Energy retired certain coal-fueled generating units as the least-cost alternative to comply with the MATS. Walter Scott, Jr. Energy Center Units 1 and 2 were retired in 2015, and George Neal Energy Center Units 1 and 2 were retired in April 2016. A fifth unit, Riverside Generating Station, was limited to natural gas combustion in March 2015.

Numerous lawsuits have been filed in the D.C. Circuit challenging the MATS. In April 2014, the D.C. Circuit upheld the MATS requirements. In November 2014, the United States Supreme Court agreed to hear the MATS appeal on the limited issue of whether the EPA unreasonably refused to consider costs in determining whether it is appropriate to regulate hazardous air pollutants emitted by electric utilities. Oral argument in the case was held before the United States Supreme Court in March 2015, and a decision was issued by the United States Supreme Court in June 2015, which reversed and remanded the MATS rule to the D.C. Circuit for further action. The United States Supreme Court held that the EPA had acted unreasonably when it deemed cost irrelevant to the decision to regulate generating facilities, and that cost, including costs of compliance, must be considered before deciding whether regulation is necessary and appropriate. The United States Supreme Court's decision did not vacate or stay implementation of the MATS rule. In December 2015, the D.C. Circuit issued an order remanding the rule to the EPA without vacating the rule. As a result, the relevant Registrants continue to have a legal obligation under the MATS rule and the respective permits issued by the states in which each respective Registrant operates to comply with the MATS rule, including operating all emissions controls or otherwise complying with the MATS requirements.

In December 2018, the EPA issued a proposed revised supplemental cost finding for the MATS, as well as the required risk and technology review under Clean Air Act Section 112. The EPA proposed to determine that it is not appropriate and necessary to regulate hazardous air pollutant emissions from generating facilities under Section 112; however, the EPA proposed to retain the emission standards and other requirements of the MATS rule, because the EPA did not propose to remove coal- and oil-fueled generating facilities from the list of sources regulated under Section 112. In May 2020, the EPA published its decision to repeal the appropriate and necessary findings in the MATS rule and retain the overall emission standards. The rule took effect in July 2020. A number of petitions for review were filed in the D.C. Circuit by parties challenging and supporting the EPA's decision to rescind the appropriate and necessary finding, which were stayed pending the EPA's plans to revisit the finding. On January 31, 2022, the EPA proposed several actions relating to the MATS. The EPA proposed to restore the appropriate and necessary finding to regulate generating facilities under Clean Air Act Section 112, reaffirming its determination made in the 2016 Supplemental Finding that it was appropriate and necessary to regulate hazardous air pollutants while expanding the rationale supporting that conclusion. The EPA also proposed to retain the 2020 risk and technology review for MATS. The 2020 risk and technology review found that current standards are protective of human health with an adequate margin of safety and that there were no developments in practices, processes or standards warranting a revision of the standard. The EPA requests comments with information regarding technology and fleet emissions performance to inform any future action related to the risk and technology review. Any additional review of the risk and technology review will be separate from this proposal. Impacts from the rule as proposed are expected to be minimal. However, until the agency takes final action on the proposal, the relevant Registrants cannot fully determine the effects of the changes to the MATS rule.

In March 2020, the D.C. Circuit issued an opinion in *Chesapeake Climate Action Network v. EPA* regarding consolidated challenges to the EPA's startup and shutdown provisions contained in the 2012 MATS rule. The MATS rule's provisions governing startup and shutdown require electric generating units comply with work practice standards as opposed to numerical limits during these periods. The EPA denied petitions for reconsideration of these provisions in 2016 and environmentalists challenged this denial. The D.C. Circuit vacated the reconsideration denials, remanding the petition to the EPA for further action. The court did not make a determination on the merits of the arguments concerning the EPA's legal authority to set work practice standards. The existing work practice standards and the alternate definition for when startup ends continue to be applicable. Until the EPA finalizes action to respond to the court's order, the relevant Registrants cannot fully determine the impacts of the remand.

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 United States, including Iowa, 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.

The first phase of the rule was implemented January 1, 2015. In November 2015, the EPA released a proposed rule that would further reduce NO_x emissions in 2017. The final "CSAPR Update Rule" was published in the *Federal Register* in October 2016 and required additional reductions in NO_x emissions beginning in May 2017. On December 6, 2018, the EPA finalized a rule to close out the CSAPR, having determined that the CSAPR Update Rule for the 2008 ozone NAAQS fully addressed Clean Air Act interstate transport obligations of 20 eastern states. The EPA determined that 2023 is an appropriate future analytic year to evaluate remaining good neighbor obligations and that there will be no remaining nonattainment or maintenance receptors with respect to the 2008 ozone NAAQS in the eastern United States in that year. Accordingly, the 20 CSAPR Update-affected states would not contribute significantly to nonattainment in, or interfere with maintenance of, any other state with regard to the 2008 ozone NAAQS. Both the CSAPR Update and the CSAPR Close-Out rules were challenged in the D.C. Circuit Court. The D.C. Circuit ruled September 13, 2019, that because the EPA allowed upwind States to continue to significantly contribute to downwind air quality problems beyond statutory deadlines, the CSAPR Update Rule provided only a partial remedy that did not fully address interstate ozone transport, and remanded the CSAPR Update Rule back to the EPA. The D.C. Circuit Court issued an opinion October 1, 2019, finding that because the CSAPR Close-Out Rule relied on the same faulty reasoning as the CSAPR Update Rule, the CSAPR Close-Out Rule must be vacated. On October 15, 2020, the EPA proposed to tighten caps on emissions of NO_x from generating facilities in 12 states in the CSAPR trading program in response to the D.C. Circuit's decision to vacate the CSAPR Update rule. The rule is intended to fully resolve 21 upwind states' remaining good neighbor obligations under the 2008 ozone NAAQS. Additional emissions reductions are required at generating facilities in 12 states, including Illinois; the EPA predicts that emissions from the remaining nine states, including Iowa and Texas, will not significantly contribute to downwind states' ability to attain or maintain the ozone standard. The EPA accepted comment on the proposal through December 15, 2020. On March 15, 2021, the EPA finalized the Revised CSAPR Update Rule largely as proposed. Significant new compliance obligations are not anticipated as a result of the rule. In June 2021, a new lawsuit was filed that challenges the Revised CSAPR Update Rule. Litigation is ongoing in the D.C. Circuit Court. Until litigation is exhausted, the relevant Registrants cannot determine whether additional action may be required.

MidAmerican Energy operates natural gas-fueled generating facilities in Iowa and BHE Renewables operates natural gas-fueled generating facilities in Texas, Illinois and New York, which are subject to the CSAPR. MidAmerican Energy has installed emissions controls at its coal-fueled generating facilities to comply with the CSAPR and may purchase emissions allowances to meet a portion of its compliance obligations. The cost of these allowances is subject to market conditions at the time of purchase and historically has not been material. MidAmerican Energy believes that the controls installed to date are consistent with the reductions to be achieved from implementation of the rule. None of PacifiCorp's, Nevada Power's or Sierra Pacific's generating facilities are subject to the CSAPR. However, in a Notice of Data Availability published in the January 6, 2017 *Federal Register*, the EPA provided preliminary estimates of which upwind states may have linkages to downwind states experiencing ozone levels at or exceeding the 2015 ozone NAAQS of 70 parts per billion, and, using similar methodology to that in the CSAPR, indicated that Utah and Wyoming could have an obligation under the "good neighbor" provisions of the Clean Air Act to reduce NO_x emissions. Until such time as a rule is finalized, the relevant Registrants cannot determine whether additional action may be required.

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.

The state of Utah issued a regional haze SIP requiring the installation of SO_2, NO_x and particulate matter controls on Hunter Units 1 and 2, and Huntington Units 1 and 2. In December 2012, the EPA approved the SO_2 portion of the Utah regional haze SIP and disapproved the NO_x and particulate matter portions. Subsequently, the Utah Division of Air Quality completed an alternative BART analysis for Hunter Units 1 and 2, and Huntington Units 1 and 2. In January 2016, the EPA published two alternative proposals to either approve the Utah SIP as written or reject the Utah SIP relating to NO_x controls and require the installation of SCR equipment at Hunter Units 1 and 2 and Huntington Units 1 and 2 within five years. The EPA's final action on the Utah regional haze SIP was effective August 4, 2016. The EPA approved in part and disapproved in part the Utah regional haze SIP and issued a federal implementation plan ("FIP") requiring the installation of SCR equipment at Hunter Units 1 and 2 and Huntington Units 1 and 2 within five years of the effective date of the rule. PacifiCorp and other parties filed requests with the EPA to reconsider and stay that decision, as well as filed motions for stay and petitions for review with the Tenth Circuit Court of Appeals ("Tenth Circuit") asking the court to overturn the EPA's actions. In July 2017, the EPA issued a letter indicating it would reconsider its FIP decision. In light of the EPA's grant of reconsideration and the EPA's position in the litigation, the Tenth Circuit held the litigation in abeyance and imposed a stay of the compliance obligations of the FIP for the number of days the stay is in effect while the EPA conducts its reconsideration process. To support the reconsideration, PacifiCorp undertook additional air quality modeling using the Comprehensive Air Quality Model with Extensions ("CAMX") dispersion model. On January 14, 2019, the state of Utah submitted a SIP revision to the EPA, which includes the updated modeling information and additional analysis. On June 24, 2019, the Utah Air Quality Board unanimously voted to approve the Utah regional haze SIP revision, which incorporates a BART alternative into Utah's regional haze SIP. 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 Utah Division of Air Quality submitted the SIP revision to the EPA for approval at the end of 2019. In January 2020, the EPA published its proposed approval of the Utah Regional Haze SIP Alternative, which makes the shutdown of the Carbon generating facility federally enforceable and adopts as BART the existing NO_x controls and emission limits on the Hunter and Huntington generating facilities. The proposed approval withdraws the FIP requirements to install SCR equipment on Hunter Units 1 and 2 and Huntington Units 1 and 2. The EPA released the final rule approving the Utah Regional Haze SIP Alternative on October 28, 2020. With the approval, the EPA also finalized its withdrawal of the FIP requirements for the Hunter and Huntington generating facilities. The Utah Regional Haze SIP Alternative took effect December 28, 2020. As a result of these actions, the Tenth Circuit dismissed the Utah regional haze petitions on January 11, 2021. 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. PacifiCorp and the state of Utah moved to intervene in the litigation. After review of the rule by the Biden administration, the EPA determined it would defend the rule and briefing in the case occurred in January and February 2022. A date for oral arguments has not been scheduled.

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. In addition, the EPA initially proposed in June 2012 to disapprove portions of the NO_x and particulate matter SIP and instead issue a FIP. The EPA withdrew its initial proposed actions on the NO_x and particulate matter SIP and the proposed FIP, published a re-proposed rule in June 2013, and finalized its determination in January 2014, which aligns more closely with the SIP proposed by the state of Wyoming. The EPA's final action on the Wyoming SIP 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 within five years (i.e., by 2019). The EPA action became final on March 3, 2014. PacifiCorp filed an appeal of the EPA's final action on Wyodak in March 2014. The state of Wyoming also filed an appeal of the EPA's final action, as did the Powder River Basin Resource Council, National Parks Conservation Association and Sierra Club. 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 EPA, United States Department of Justice, state of Wyoming and PacifiCorp executed a settlement agreement December 16, 2020, removing the requirement to install SCR in lieu of monthly and annual NO_x emissions limits. The settlement agreement was subject to a comment period which ended July 6, 2021. Litigation in the Tenth Circuit remains stayed pending finalization of the settlement agreement. The EPA did not proceed with final approval of the settlement agreement for Wyodak and is currently engaged with Wyoming and PacifiCorp concerning alternative paths for resolution. In June 2014, the Wyoming Department of Environmental Quality issued a revised BART permit allowing Naughton Unit 3 to operate on coal through 2017 and providing for natural gas conversion of the unit in 2018. In 2017, the department approved an extension of the compliance date for Naughton Unit 3 to align with the requirements of the Wyoming SIP extending the requirement to cease coal firing to no later than January 30, 2019. The EPA issued final approval of the Wyoming SIP, including the Naughton Unit 3 gas conversion, on March 21, 2019. PacifiCorp removed the unit from coal-fueled service on January 30, 2019 and completed the gas conversion in August 2020. On February 5, 2019, PacifiCorp submitted a reasonable progress reassessment permit application and reasonable progress determination for Jim Bridger Units 1 and 2, seeking a rescission of the December 2017 permit requiring the installation of SCR, to be replaced with permit imposing plant-wide emission limits to achieve better modeled visibility, fewer overall environmental impacts and lower costs of compliance. In May 2020, the Wyoming Air Quality Division issued a permit approving PacifiCorp's monthly and annual NO_x and SO_2 emission limits on the four Jim Bridger units and submitted a regional haze SIP revision to the EPA. The revised SIP would grant approval of PacifiCorp's Jim Bridger reasonable progress reassessment application and incorporates PacifiCorp's proposed emission limits in lieu of the requirement to install SCR systems on Jim Bridger Units 1 and 2. On December 27, 2021, Wyoming's governor issued an emergency suspension order under Section 110(g) of the Clean Air Act, allowing the operation of Jim Bridger Unit 2 through April 30, 2022, while the state, the EPA and PacifiCorp continue settlement discussions. On January 18, 2022, the EPA proposed to reject the SIP revisions. The EPA took comment on the proposal through February 17, 2022. 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 under Sections 201 and 209(a) of the Wyoming Environmental Quality Act, 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 and as forecasted in PacifiCorp's 2021 IRP, PacifiCorp must convert both units to natural gas and begin meeting emissions limits consistent with that conversion by January 1, 2024. In addition, PacifiCorp must propose an RFP by January 1, 2023, for carbon capture technology at Jim Bridger Units 3 and 4.

The state of Colorado 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 identified a December 31, 2025, retirement date for Craig Unit 1 in its 2017 and 2019 IRPs.

Until the EPA takes final action in each state and decisions have been made in the pending appeals, PacifiCorp cannot fully determine the impacts of the Regional Haze Rule on its respective generating facilities.

Water Quality Standards

The federal Water Pollution Control Act ("Clean Water Act") establishes the framework for maintaining and improving water quality in the United States 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 United States 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 and MidAmerican Energy are assessing the options for compliance at their generating facilities impacted by the final rule and will complete impingement and entrainment studies. 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 United States 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. The standards are required to be met as soon as possible after the effective date of the final rule, but no later than eight years thereafter. The costs of compliance with the cooling water intake structure rule cannot be fully determined until the prescribed studies are conducted and the respective state environmental agencies review the studies to determine whether additional mitigation technologies should be applied. 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 do not utilize once-through cooling water intake or discharge structures at any of their generating facilities. All of the Nevada Power and Sierra Pacific generating stations are designed to have either minimal or zero discharge; therefore, they are not impacted by the §316(b) final rule.

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. These guidelines, which had not been revised since 1982, were revised in response to the EPA's concerns that the addition of controls for air emissions has changed the effluent discharged from coal- and natural gas-fueled generating facilities. Under the originally promulgated guidelines, permitting authorities were required to include the new limits in each impacted facility's discharge permit upon renewal with the new limits to be met as soon as possible, beginning November 1, 2018 and fully implemented by December 31, 2023. On April 5, 2017, a request for reconsideration and administrative stay of the guidelines was filed with the EPA. The EPA granted the request for reconsideration on April 12, 2017, imposed an immediate administrative stay of compliance dates in the rule that had not passed judicial review and requested the court stay the pending litigation over the rule until September 12, 2017. On June 6, 2017, the EPA proposed to extend many of the compliance deadlines that would otherwise occur in 2018 and on September 18, 2017, the EPA issued a final rule extending certain compliance dates for flue gas desulfurization wastewater and bottom ash transport water limits until November 1, 2020. In a separate action, on April 12, 2019, the Fifth Circuit Court of Appeals vacated two aspects of the final effluent limitation guidelines, concerning discharge limits for (1) legacy wastewater from ash transport or treatment systems and (2) combustion residual leachate from landfills or settling ponds. The Fifth Circuit found that the EPA's own data did not support the agency's conclusion that impoundments were the best technology available for these two waste streams. The EPA must now complete a new effluent limitation guideline for these discharge limits. On November 22, 2019, the EPA proposed updates to the 2015 rule, specifically addressing flue gas desulfurization wastewater and bottom ash transport water. The rule was finalized in October 2020 and took effect December 14, 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. The rule does not address the wastestreams at issue in the Fifth Circuit Court of Appeal's April 2019 decision. 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.

In April 2014, the EPA and the United States Army Corps of Engineers ("Corps of Engineers") issued a joint proposal to address "waters of the United States" to clarify protection under the Clean Water Act for streams and wetlands. The proposed rule comes as a result of United States Supreme Court decisions in 2001 and 2006 that created confusion regarding jurisdictional waters that were subject to permitting under either nationwide or individual permitting requirements. The final rule was released in May 2015 but was appealed in multiple courts and a nationwide stay on the implementation of the rule was issued in October 2015. On January 13, 2017, the United States Supreme Court granted a petition to address jurisdictional challenges to the rule. The EPA plans to undertake a two-step process, with the first step to repeal the 2015 rule and the second step to carry out a notice-and-comment rulemaking in which a substantive re-evaluation of the definition of the "waters of the United States" will be undertaken. On July 27, 2017, the EPA and the Corps of Engineers issued a proposal to repeal the final rule and recodify the pre-existing rules pending issuance of a new rule, which was finalized September 12, 2019. On January 22, 2018, the United States Supreme Court issued its decision related to the jurisdictional challenges to the rule, holding that federal district courts, rather than federal appeals courts, have proper jurisdiction to hear challenges to the rule and instructed the Sixth Circuit Court of Appeals to dismiss the petitions for review for lack of jurisdiction, clearing the way for imposition of the rule in certain states barring final action by the EPA to formalize the extension of the compliance deadline. On December 11, 2018, the EPA and the Corps of Engineers proposed a revised definition of "waters of the United States" that is intended to further clarify jurisdictional questions, eliminate case-by-case determinations and narrow Clean Water Act jurisdiction to align with Justice Scalia's 2006 opinion in *Rapanos v. United States*. On January 23, 2020, the EPA and the Corps of Engineers signed the final rule narrowing the federal government's permitting authority under the Clean Water Act. The new Navigable Waters Protection Rule, which took effect 60 days after it was published in the *Federal Register*, redefines what waters qualify as navigable waters of the United States and are under Clean Water Act jurisdiction. Under the new rule, the Clean Water Act is considered to cover territorial seas and traditional navigable waters; tributaries that flow into jurisdictional waters; wetlands that are directly adjacent to jurisdictional waters; and lakes, ponds and impoundments of jurisdictional waters. On June 9, 2021, the EPA and the Corps of Engineers announced their intention to again revise the definition of "waters of the United States." After reviewing the Navigable Waters Protection Rule in accordance with Executive Order 13990, the agencies determined that the rule significantly reduced clean water protections. The agencies announced their intention to restore the clean water protections that were in place prior to the implementation of the "waters of the United States" rule in 2015. On August 30, 2021, the United States District Court for the District of Arizona vacated the Navigable Waters Protection Rule and the agencies quickly announced that they would no longer implement the rule nationwide. As a result, the agencies are relying on the pre-2015 regulatory definition of "waters of the United States" until they promulgate a new definition. Projects that are already permitted under the Navigable Waters Protection Rule and those that received an approved jurisdictional determination in reliance on the rule may continue to rely on those authorizations until they expire. Until the agencies take final action to update the definition of "waters of the United States," impacts to the relevant Registrants cannot be determined.

In April 2020, the United States Supreme Court established a new test for Clean Water Act jurisdiction in *County of Maui, Hawaii v. Hawaii Wildlife Fund*, finding that the statute can cover discharges of contaminated groundwater in certain circumstances. The United States Supreme Court outlined a seven-factor test to determine whether discharges conveyed through groundwater to surface water are "functionally equivalent" to direct discharges, finding that the time it takes for pollutants to travel through groundwater and the distance traveled are the two most important factors in the test. The United States Supreme Court remanded *County of Maui, Hawaii* to the Ninth Circuit Court of Appeals for further adjudication, which subsequently remanded the case to the district court to determine whether additional discovery is needed before applying the new seven-factor test. The EPA finalized guidance January 14, 2021, implementing *County of Maui, Hawaii*. The EPA utilized the United States Supreme Court's seven factors, plus an additional factor for the design and performance of the system or facility from which the pollutant is reached, to determine whether pollutants that reach surface waters after traveling through groundwater are a "functional equivalent" to a direct discharge that require a permit. Until the functional equivalent test and guidance are applied by the courts, the Registrants cannot determine the impact of this case on their operations.

In April 2020, the United States District Court of the District of Montana vacated nationwide permit 12, which provides an expedited route for projects like oil and gas pipelines and utility lines to achieve compliance with the Clean Water Act, finding that the Corps of Engineers, which implements the nationwide permit program, failed to conduct necessary programmatic consultation of nationwide permit 12 under the Endangered Species Act. The district court's vacatur, which was subsequently limited just to the Keystone XL pipeline project, the subject of the initial lawsuit, is on appeal to the Ninth Circuit Court of Appeals. On January 13, 2021, the Corps of Engineers finalized a rule modifying its nationwide permit program for certain activities affecting waters of the United States. The final rule restructures the nationwide permit program for utility lines by splitting the existing nationwide permit 12 into three separate nationwide permits – one for oil and gas, including pipelines; one for electrical and telecommunications; and one for water/sewer and other utilities. The Corps of Engineers included a biological assessment for the final rule but did not conduct a formal Endangered Species Act consultation in connection with reissuance of the nationwide permits. The Corps of Engineers reissued and revised 12 of 52 and added four new nationwide permits, which will be effective for a period of five years. The remaining nationwide permits are scheduled for renewal in advance of expiration in 2022. Until the nationwide permit challenges are fully litigated, the Registrants cannot determine the impact of this case on their operations.

Coal Combustion Byproduct Disposal

In May 2010, the EPA released a proposed rule to regulate the management and disposal of coal combustion byproducts under the RCRA. The final rule was released by the EPA on December 19, 2014, was published in the *Federal Register* on April 17, 2015 and was effective on October 19, 2015. The final 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 may need to be closed unless they can meet the more stringent regulatory requirements. The final rule requires regulated entities to post annual groundwater monitoring and corrective action reports. The first of these reports was posted to the respective Registrant's coal combustion rule compliance data and information websites in March 2018. Based on the results in those reports, additional action may be required under the rule.

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 in 2015, resulting in settlement of some of the issues and subsequent regulatory action by the EPA, including subjecting inactive surface impoundments to regulation. Oral argument was held by the D.C. Circuit on November 20, 2017 over certain portions of the 2015 rule that had not been settled or otherwise remanded. On August 21, 2018, the D.C. Circuit issued its opinion in *Utility Solid Waste Activities Group v. EPA*, finding it was arbitrary and capricious for EPA to allow unlined ash ponds to continue operating until some unknown point in the future when groundwater contamination could be detected. The D.C. Circuit vacated the closure section of the CCR rule and remanded the issue of unlined ponds to the EPA for reconsideration with specific instructions to consider harm to the environment, not just to human health. The D.C. Circuit also held the EPA's decision to not regulate legacy ponds was arbitrary and capricious. While the D.C. Circuit's decision was pending, the EPA, on March 15, 2018, issued a proposal to address provisions of the final CCR rule that were remanded back to the agency on June 14, 2016, by the D.C. Circuit. The proposal included provisions that establish alternative performance standards for owners and operators of CCR units located in states that have approved permit programs or are otherwise subject to oversight through a permit program administered by the EPA. The EPA finalized the first phase of the CCR rule amendments on July 30, 2018, with an effective date of August 28, 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 proposal modifies the definition of "beneficial use" by replacing a mass-based threshold with new location-based criteria for triggering the need to conduct an environmental demonstration; establishes a definition of "CCR storage pile" to address the temporary storage of CCR on the ground, depending on whether the material is destined for disposal or beneficial use; makes certain changes to the rule's annual groundwater monitoring and corrective action reports to make it easier for the public to see and understand the data contained within the reports; modifies the requirements related to facilities' publicly available CCR rule websites to make the information more readily available; and establishes a risk-based groundwater monitoring protection standard for boron in the event the EPA decides to add boron to Appendix IV in the CCR rule. The EPA accepted comments on the Phase 2 proposal through October 15, 2019. On December 22, 2020, the EPA released a notice of data availability relating to the Phase 2 proposal to revise the CCR rule's definition of beneficial use and provisions governing piles of CCR on- and off-site prior to beneficial use. The new information presented by the notice includes data and information the EPA received during the comment period on the Phase 2 proposal. The EPA accepted comment on the notice of data availability through February 22, 2021. The EPA has not announced an anticipated timeline for completing the Phase 2 rule. In February 2020, the EPA proposed a federal CCR permit program as required by the WIIN Act of 2016. The proposal would require permits for all CCR units in states that do not have an EPA-approved CCR program. The proposal would establish individual, general and permit-by-rule permits; a tiered schedule for applications to prioritize permits for high-hazard potential CCR units; and postpone timelines for permit applications for all other CCR units. The EPA has not announced an anticipated timeline for completing the federal CCR permit rule. 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. Issues identified by the EPA include the definition of a legacy impoundment, information on the universe of legacy impoundments, the types of regulatory requirements that should apply to legacy impoundments, and the EPA's regulatory authority to regulate legacy impoundments under RCRA subtitle D. The EPA accepted comment on the advanced notice through February 12, 2021. Until the proposals are finalized and fully litigated, the Registrants cannot determine whether additional action may be required.

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 was finalized in August 2020 and establishes a new deadline of April 11, 2021, by which all unlined surface impoundments (including clay lined impoundments that do not otherwise meet the definition of "lined") 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. In addition to these closure deadline provisions, the Part A rule also finalized changes to the CCR rule's annual groundwater monitoring and corrective action reports and modified requirements related to CCR rule compliance websites initially proposed in the Phase 2 rule. 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 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. In December 2020, the EPA finalized its Holistic Approach to Closure: Part B rule ("Part B rule"), which establishes procedures for owners and operators of unlined ash ponds to demonstrate that the liner systems or underlying soils for these units perform as well as the liner criteria in the CCR rule. Additional provisions included in the proposed rule but not finalized, including the use of CCR in closure activities and allowing for the completion of groundwater corrective action during the post-closure care period, will be addressed in future rulemakings. As finalized, none of the relevant Registrants anticipate exercising the provisions of the Part B rule.

Separately, on August 10, 2017, the EPA issued proposed permitting guidance on how states' CCR permit programs should comply with the requirements of the final rule as authorized under the December 2016 Water Infrastructure Improvements for the Nation Act. Using that guidance, the state of Oklahoma applied for EPA approval of its state program, and, on June 28, 2018, the EPA's approval of the application was published in the *Federal Register*. Environmental groups, including Waterkeeper Alliance and the Sierra Club, filed suit in the D.C. Circuit on September 26, 2018, alleging that the EPA unlawfully approved Oklahoma's permit program. This suit also incorporates claims first identified in a July 26, 2018 notice of intent to sue that alleged the EPA failed to perform nondiscretionary duties related to the development and publication of minimum guidelines for public participation in the approval of state permit programs for CCR. To date, none of the states in which the Registrants operate has applied for EPA approval of state permitting authority. The state of Utah adopted the federal final rule in September 2016, which required PacifiCorp to submit permit applications for two of its landfills by March 2017. It is anticipated that the state of Utah will apply for EPA approval of its CCR permit program prior to the end of 2021. In 2019, the state of Wyoming proposed to adopt state rules which incorporate the final federal rule by reference. It is anticipated that Wyoming will finalize its rule and seek the EPA's approval to implement a state permit program in 2021.

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.

On January 20, 2021, President Biden issued an executive order on climate change which also required review of actions taken over the preceding four years that were harmful to "public health, environment, unsupported by the best available science, or otherwise not in the national best interest." The order included a non-exhaustive list of regulatory actions to be reviewed by the issuing agencies, including New Source Performance Standards for the power sector and the oil and gas sector, rescission of the Clean Power Plan, particulate matter and ozone NAAQS, steam electric effluent limitation guidelines, waters of the United States, reissuance of nationwide permits, and the phase one, part one and holistic approach to closure: parts A and B under the CCR rule. In addition, the Biden administration issued a regulatory freeze memorandum that prohibits submission of rules and guidance documents to the *Federal Register* without direct review, requires immediate withdrawal of rules and guidance documents submitted to the *Federal Register* but not yet published, and, for rules and guidance documents published but not yet having taken effect, consideration of a 60-day delay and possible additional comment period. Until the issuing agency completes its review and takes final action consistent with these directives, the relevant Registrant cannot determine whether additional action under any of these rules will be necessary.

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 the relicensing of 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.

Corporate and Financial 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. 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:

- 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, 2021, BHE had the following outstanding obligations:

- senior unsecured debt of $13.0 billion;
- junior subordinated debentures of $100 million;
- guarantees and letters of credit in respect of subsidiaries, equity method investments and other related parties aggregating $1.4 billion; and
- commitments, subject to satisfaction of certain specified conditions, to provide equity contributions in support of renewable tax equity investments totaling $356 million.

BHE's consolidated subsidiaries also have significant amounts of outstanding debt, which totaled $38.7 billion as of December 31, 2021. 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 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.

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, and the potential pool of investors and funding sources would likely decrease. Further, access to the commercial paper market could be significantly limited, resulting in higher interest costs.

Similarly, any downgrade 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.

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.

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 and Sierra Pacific 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.

Business Risks

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.

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, 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 or other equipment or processes, which could lead to catastrophic events; unscheduled outages; strikes, lockouts or other labor-related actions; shortages of qualified labor; transmission and distribution system constraints; failure to obtain, renew or maintain rights-of-way, easements and leases on United States federal, Native American, First Nations or tribal lands; terrorist activities or military or other actions, including 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 pipeline systems; 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, litigation, wars, terrorism, pandemics and embargoes. A catastrophic event might result in injury or loss of life, extensive property damage or environmental or natural resource damages. 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, its revenue could decrease and its expenses could increase due to the need to obtain energy from more expensive sources.

Further, 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. 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.

The Registrants are subject to increasing risk from catastrophic wildfires and may be unable to obtain enough insurance coverage at a reasonable cost or at all to adequately protect the Registrants from liability, which could materially affect the Registrants financial results and liquidity.

The risk of catastrophic and severe wildfires has increased in the western United States giving rise to 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 territory 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 distribution and transmission 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.

Damage claims against PacifiCorp for the 2020 Wildfires (as defined below) may materially affect PacifiCorp's financial condition and results of operations.

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 damage, personal injuries and loss of life and widespread power outages in Oregon and Northern California (the "2020 Wildfires"). The wildfires spread across certain parts of PacifiCorp's service territory and surrounding areas across multiple counties in Oregon and California. Investigations into the cause and origin of each wildfire are complex and ongoing. Several lawsuits and complaints have been filed in Oregon and California associated with the wildfires, and it is possible that additional lawsuits and complaints against PacifiCorp may be filed. If PacifiCorp is found liable for damages related to the 2020 Wildfires and is unable to, or believes that it will be unable to, recover those damages through insurance or customer rates, or access the bank and capital markets on reasonable terms, PacifiCorp's financial results could be adversely affected. 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 2020 Wildfires.

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 legislation related to such epidemics, pandemics or other outbreaks (or other similar laws, regulations, 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.

Each Registrant is 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 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 initiatives regarding deregulation and restructuring of the utility industry, are continually being proposed and enacted that impose new or revised requirements or standards on each Registrant.

Each Registrant is required to comply with numerous federal, state, local and 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 of 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 United States, and 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 revenues within each Registrant's service territories; new environmental 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. 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 United States 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, 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 risk 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 service 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 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. Any of these consequences could adversely affect each Registrant's financial results.

FERC Jurisdiction

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 system's regulatory cost of service that are associated with the construction, operation and maintenance of their pipeline system 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.

GEMA Jurisdiction

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.

AUC Jurisdiction

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 regulations 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.

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 those of many large businesses, certain of the Registrant's technology systems have been subject to computer viruses, malicious codes, unauthorized access, phishing efforts, denial-of-service attacks and other cyber attacks and each Registrant expects to be subject to similar attacks in the future as such attacks become more sophisticated and frequent. A significant disruption or failure of its technology systems by physical or cyber 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.

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 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.

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 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 United States 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 and Nevada Power, 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 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 expense 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.

Potential terrorist activities and the impact of military or other actions, 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 United States government has issued warnings that energy assets, specifically pipeline, nuclear generation, transmission and other electric utility infrastructure, are potential targets for terrorist attacks. Political, economic, social or financial market instability or damage to or interference with the operating assets of the Registrants, customers or suppliers may result in business interruptions, lost revenue, higher commodity prices, 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 its 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.

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 expense, 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 expense 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 United States 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.

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' revenues are 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 continues to monitor 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 any Registrant's wholesale suppliers' or customers' financial condition deteriorates or they otherwise become unable to pay, it could have a significant adverse impact on each 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 23% and 12%, respectively, of distribution revenue in 2021. 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 United States 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.

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 United States 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 United States 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, United States dollars or a currency freely convertible into United States 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), 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.

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 and 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 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.

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

Inflation and increases in commodity prices and fuel transportation 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 costs of inflation on to its customers. If each Registrant is unable to manage cost increases or pass them on to its customers, its financial results could be adversely affected.

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 United States;
- 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.

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 United States, 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 United States or globally may adversely affect the United States' 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.

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 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 or permitting of facilities. Any of these outcomes could have a material adverse effect on such Registrant's financial results.

Item 1B. Unresolved Staff Comments

Not applicable.

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, 2021:

Energy Source	Entity	Location by Significance	Facility Net Capacity (MWs)	Net Owned Capacity (MWs)
Wind	PacifiCorp, MidAmerican Energy and BHE Renewables	Iowa, Wyoming, Texas, Nebraska, Washington, California, Illinois, Montana, Oregon and Kansas	11,517	11,517
Natural gas	PacifiCorp, MidAmerican Energy, NV Energy, BHE Renewables and BHE Canada	Nevada, Utah, Iowa, Illinois, Washington, Wyoming, Oregon, Texas, New York, Arizona and Canada	11,112	10,833
Coal	PacifiCorp, MidAmerican Energy and NV Energy	Wyoming, Iowa, Utah, Nevada, Colorado and Montana	13,235	8,193
Solar	BHE Renewables and NV Energy	California, Texas, Arizona, Minnesota and Nevada	1,719	1,571
Hydroelectric	PacifiCorp, MidAmerican Energy and BHE Renewables	Washington, Oregon, Idaho, California, Utah, Hawaii, Montana, Illinois and Wyoming	1,149	1,149
Nuclear	MidAmerican Energy	Illinois	1,823	456
Geothermal	PacifiCorp and BHE Renewables	California and Utah	377	377
		Total	40,932	34,096

Additionally, as of December 31, 2021, the Company has electric generating facilities that are under construction in Nevada, Iowa and Canada having total Facility Net Capacity and Net Owned Capacity of 421 MWs.

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 United States; 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 United States 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 United States 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

On September 30, 2020, a putative class action complaint against PacifiCorp was filed, captioned *Jeanyne James et al. v. PacifiCorp et al*., Case No. 20cv33885, Circuit Court, Multnomah County, Oregon. The complaint was filed by Oregon residents and businesses who seek to represent a class of all Oregon citizens and entities whose real or personal property was harmed beginning on September 7, 2020, by wildfires in Oregon allegedly caused by PacifiCorp. On November 3, 2021, the plaintiffs filed an amended complaint to limit the class to include Oregon citizens allegedly impacted by the Echo Mountain, South Obenchain, Two Four Two and Santiam Canyon (also known as Beachie Creek) fires, as well as to add claims for noneconomic damages. The amended complaint alleges 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 the following damages for the plaintiffs and the putative class: (i) noneconomic damages, including mental suffering, emotional distress, inconvenience and interference with normal and usual activities, in excess of $1 billion; (ii) damages for real and personal property and other economic losses of not less than $600 million; (iii) double the amount of property and economic damages; (iv) treble damages for specific costs associated with loss of timber, trees and shrubbery; (v) double the damages for the costs of litigation and reforestation; (vi) prejudgment interest; and (vii) reasonable attorney fees, investigation costs and expert witness fees. The plaintiffs demand a trial by jury and have reserved their right to further amend the complaint to allege claims for punitive damages.

On August 20, 2021, a complaint against PacifiCorp was filed, captioned *Shylo Salter et al. v. PacifiCorp*, Case No. 21cv33595, Multnomah County, Oregon, in which two complaints, Case No. 21cv09339 and Case No. 21cv09520, previously filed in Circuit Court, Marion County, Oregon, were combined. The plaintiffs voluntarily dismissed the previously filed complaints in Marion County, Oregon. The refiled complaint was filed by Oregon residents and businesses who allege that they were injured by the Beachie Creek Fire, which the plaintiffs allege began on or around September 7, 2020, but which government reports indicate began on or around August 16, 2020. The complaint alleges that PacifiCorp's assets contributed to the Beachie Creek Fire and that PacifiCorp acted with gross negligence, among other things. The complaint seeks the following damages: (i) damages related to real and personal property in an amount determined by the jury to be fair and reasonable, estimated not to exceed $75 million; (ii) other economic losses in an amount determined by the jury to be fair and reasonable, but not to exceed $75 million; (iii) noneconomic damages in the amount determined by the jury to be fair and reasonable, but not to exceed $500 million; (iv) double the damages for economic and property damages under specified Oregon statutes; (v) alternatively, treble the damages under specified Oregon statutes; (vi) attorneys' fees and other costs; and (vii) pre- and post-judgment interest. The plaintiffs demand a trial by jury and have reserved their right to amend the complaint with an intent to add a claim for punitive damages.

Other individual lawsuits alleging similar claims have been filed in Oregon and California related to the 2020 Wildfires. Investigations into the causes and origins of those 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.

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, family members and related or affiliated entities of the late Mr. Walter Scott, Jr., a former member of BHE's Board of Directors, and Mr. Gregory E. Abel, BHE's Chair, 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 $150 million in 2021 and $— million in 2020.

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. Neither MidAmerican Funding nor MidAmerican Energy declared or paid any cash distributions or dividends to its sole member or shareholder in 2021 and 2020.

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 $213 million in 2021 and $155 million in 2020.

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 $— million in 2021 and $20 million in 2020.

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 did not declare or pay cash distributions to BHE GT&S in 2021 or 2020. Eastern Energy Gas declared and paid cash distributions to DEI of $4.3 billion in 2020.

Item 6. [Reserved]

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

Berkshire Hathaway Energy Company and its subsidiaries	102
PacifiCorp and its subsidiaries	195
MidAmerican Funding, LLC and its subsidiaries and MidAmerican Energy Company	252
Nevada Power Company and its subsidiaries	321
Sierra Pacific Power Company and its subsidiaries	364
Eastern Energy Gas Holdings, LLC and its subsidiaries	405

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Berkshire Hathaway Energy Company and its subsidiaries	119
PacifiCorp and its subsidiaries	207
MidAmerican Funding, LLC and its subsidiaries and MidAmerican Energy Company	265
Nevada Power Company and its subsidiaries	331
Sierra Pacific Power Company and its subsidiaries	374
Eastern Energy Gas Holdings, LLC and its subsidiaries	412

Item 8. Financial Statements and Supplementary Data

Berkshire Hathaway Energy Company and its subsidiaries	
Report of Independent Registered Public Accounting Firm	125
Consolidated Balance Sheets	128
Consolidated Statements of Operations	130
Consolidated Statements of Comprehensive Income	131
Consolidated Statements of Changes in Equity	132
Consolidated Statements of Cash Flows	133
Notes to Consolidated Financial Statements	134
PacifiCorp and its subsidiaries	
Report of Independent Registered Public Accounting Firm	211
Consolidated Balance Sheets	214
Consolidated Statements of Operations	216
Consolidated Statements of Comprehensive Income	217
Consolidated Statements of Changes in Shareholders' Equity	218
Consolidated Statements of Cash Flows	219
Notes to Consolidated Financial Statements	220
MidAmerican Energy Company	
Report of Independent Registered Public Accounting Firm	268
Balance Sheets	270
Statements of Operations	272
Statements of Changes in Shareholder's Equity	273
Statements of Cash Flows	274
Notes to Financial Statements	275
MidAmerican Funding, LLC and its subsidiaries	
Report of Independent Registered Public Accounting Firm	304
Consolidated Balance Sheets	306
Consolidated Statements of Operations	308
Consolidated Statements of Changes in Member's Equity	309
Consolidated Statements of Cash Flows	310
Notes to Consolidated Financial Statements	311
Nevada Power Company and its subsidiaries	
Report of Independent Registered Public Accounting Firm	335
Consolidated Balance Sheets	337
Consolidated Statements of Operations	338
Consolidated Statements of Changes in Shareholder's Equity	339
Consolidated Statements of Cash Flows	340
Notes to Consolidated Financial Statements	341
Sierra Pacific Power Company and its subsidiaries	
Report of Independent Registered Public Accounting Firm	377
Consolidated Balance Sheets	379
Consolidated Statements of Operations	380
Consolidated Statements of Changes in Shareholder's Equity	381
Consolidated Statements of Cash Flows	382
Notes to Consolidated Financial Statements	383
Eastern Energy Gas Holdings, LLC and its subsidiaries	
Report of Independent Registered Public Accounting Firm	415
Consolidated Balance Sheets	417
Consolidated Statements of Operations	419
Consolidated Statements of Comprehensive Income	420
Consolidated Statements of Changes in Equity	421
Consolidated Statements of Cash Flows	422
Notes to Consolidated Financial Statements	423

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 entities, including MES, corporate functions and intersegment eliminations.

Results of Operations

Overview

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

	2021	2020	Change		2020	2019	Change	
Operating revenue:								
PacifiCorp	$ 5,296	$ 5,341	$ (45)	(1)%	$ 5,341	$ 5,068	$ 273	5 %
MidAmerican Funding	3,547	2,728	819	30	2,728	2,927	(199)	(7)
NV Energy	3,107	2,854	253	9	2,854	3,037	(183)	(6)
Northern Powergrid	1,188	1,022	166	16	1,022	1,013	9	1
BHE Pipeline Group	3,544	1,578	1,966	*	1,578	1,131	447	40
BHE Transmission	731	659	72	11	659	707	(48)	(7)
BHE Renewables	981	936	45	5	936	932	4	—
HomeServices	6,215	5,396	819	15	5,396	4,473	923	21
BHE and Other	541	438	103	24	438	556	(118)	(21)
Total operating revenue	$25,150	$20,952	$ 4,198	20 %	$20,952	$19,844	$ 1,108	6 %
Earnings on common shares:								
PacifiCorp	$ 889	$ 741	$ 148	20 %	$ 741	$ 773	$ (32)	(4)%
MidAmerican Funding	883	818	65	8	818	781	37	5
NV Energy	439	410	29	7	410	365	45	12
Northern Powergrid	247	201	46	23	201	256	(55)	(21)
BHE Pipeline Group	807	528	279	53	528	422	106	25
BHE Transmission	247	231	16	7	231	229	2	1
BHE Renewables(1)	451	521	(70)	(13)	521	431	90	21
HomeServices	387	375	12	3	375	160	215	*
BHE and Other	1,319	3,092	(1,773)	(57)	3,092	(467)	3,559	*
Total earnings on common shares	$ 5,669	$ 6,917	$ (1,248)	(18)%	$ 6,917	$ 2,950	$ 3,967	*

(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 decreased $1,248 million for 2021 compared to 2020. Included in these results was a pre-tax unrealized gain in 2021 of $1,796 million ($1,777 million after-tax) compared to a pre-tax unrealized gain in 2020 of $4,774 million ($3,470 million after-tax) on the Company's investment in BYD Company Limited. Excluding the impact of this item, adjusted earnings on common shares in 2021 was $3,892 million, an increase of $445 million, or 13%, compared to adjusted earnings on common shares in 2020 of $3,447 million.

The decrease in net income attributable to BHE shareholders for 2021 compared to 2020 was primarily due to:

- The Utilities' earnings increased $242 million reflecting higher electric utility margin, favorable income tax expense, from higher PTCs recognized of $139 million and the impacts of ratemaking, and lower operations and maintenance expense, partially offset by higher depreciation and amortization expense. Electric retail customer volumes increased 3.8% for 2021 compared to 2020, 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 $46 million, primarily due to higher distribution performance, lower write-offs of gas exploration costs and $16 million from the weaker United States dollar, partially offset by the comparative unfavorable impact of deferred income tax charges ($109 million in second quarter 2021 and $35 million in third quarter 2020) related to enacted increases in the United Kingdom corporate income tax rate;
- BHE Pipeline Group's earnings increased $279 million, primarily due to $244 million of incremental earnings at BHE GT&S;
- BHE Renewables' earnings decreased $70 million, primarily due to lower tax equity investment earnings from the February 2021 polar vortex weather event, partially offset by earnings from tax equity investment projects reaching commercial operation and higher operating performance from owned renewable energy projects; and
- BHE and Other's earnings decreased $1,773 million, primarily due to the $1,693 million change in the after-tax unrealized position of the Company's investment in BYD Company Limited and $95 million of higher dividends on BHE's 4.00% Perpetual Preferred Stock issued in October 2020, partially offset by favorable comparative consolidated state income tax benefits.

Earnings on common shares increased $3,967 million for 2020 compared to 2019. Included in these results was a pre-tax unrealized gain in 2020 of $4,774 million ($3,470 million after-tax) compared to a pre-tax unrealized loss in 2019 of $313 million ($227 million after-tax) on the Company's investment in BYD Company Limited. Excluding the impact of this item, adjusted earnings on common shares in 2020 was $3,447 million, an increase of $270 million, or 9%, compared to adjusted earnings on common shares in 2019 of $3,177 million.

The increase in earnings on common shares for 2020 compared to 2019 was primarily due to:

- The Utilities' earnings increased $50 million with favorable performance at all four utilities (electric retail customer volumes increased 0.1%), including $193 million of higher PTCs recognized, offset by a comparative increase in wildfire and other storm restoration costs, primarily at PacifiCorp;
- Northern Powergrid's earnings decreased $55 million, mainly due to a deferred income tax charge in 2020 from an enacted increase in the United Kingdom corporate income tax rate;
- BHE Pipeline Group's earnings increased $106 million, primarily due to $73 million of incremental earnings at BHE GT&S and a favorable rate case settlement at Northern Natural Gas;
- BHE Renewables' earnings increased $90 million, primarily due to increased income tax benefits from renewable wind tax equity investments, largely from projects reaching commercial operation, offset by lower earnings from geothermal and natural gas facilities;
- HomeServices' earnings increased $215 million, primarily due to higher earnings from mortgage services (71% increase in funded mortgage volume) and brokerage services (13% increase in closed transaction volume) largely attributable to the favorable interest rate environment; and
- BHE and Other's earnings increased $3,559 million, primarily due to the $3,697 million change in the after-tax unrealized position of the Company's investment in BYD Company Limited offset by higher BHE corporate interest expense and unfavorable comparative consolidated state income tax benefits.

Reportable Segment Results

PacifiCorp

Operating revenue decreased $45 million for 2021 compared to 2020, primarily due to lower retail revenue of $98 million, partially offset by higher wholesale and other revenue of $53 million. Retail revenue decreased mainly due to $234 million from the Utah and Oregon general rate case orders issued in 2020 (fully offset in expense, primarily depreciation) and price impacts of $41 million from lower rates primarily due to certain general rate case orders, partially offset by higher customer volumes of $177 million. Retail customer volumes increased 3.1%, primarily due to higher customer usage, an increase in the average number of customers and the favorable impact of weather. Wholesale and other revenue increased mainly due to higher wheeling revenue, average wholesale prices and REC sales, partially offset by $34 million from the Oregon RAC settlement (fully offset in depreciation expense) recognized in 2020.

Earnings increased $148 million for 2021 compared to 2020, primarily due to favorable income tax expense from higher PTCs recognized of $75 million from new wind-powered generating facilities placed in-service, and the impacts of ratemaking, lower operations and maintenance expense of $178 million and higher utility margin of $145 million, partially offset by higher depreciation and amortization expense of $255 million and lower allowances for equity and borrowed funds used during construction of $72 million. Operations and maintenance expense decreased primarily due to lower costs associated with wildfires and the Klamath Hydroelectric Settlement Agreement and lower thermal plant maintenance expense, partially offset by higher costs associated with additional wind-powered generating facilities placed in-service as well as higher distribution maintenance costs. Utility margin increased primarily due to the higher retail customer volumes, higher wheeling and wholesale revenue and higher deferred net power costs in accordance with established adjustment mechanisms, partially offset by higher purchased power and thermal generation costs, the price impacts from lower retail rates and higher wheeling expenses. The increase in depreciation and amortization expense was primarily due to the impacts of a depreciation study effective January 1, 2021, as well as additional assets placed in-service.

Operating revenue increased $273 million for 2020 compared to 2019, primarily due to higher retail revenue of $250 million and higher wholesale and other revenue of $23 million. Retail revenue increased primarily due to $234 million from the amortization of certain existing regulatory balances to offset the accelerated depreciation of certain property, plant and equipment and the accelerated amortization of certain regulatory asset balances in relation to Utah and Oregon general rate case orders issued in December 2020. The increase in retail revenue was also due to price impacts of $49 million from changes in sales mix, partially offset by lower customer volumes of $34 million. The increase in wholesale and other revenue was mainly due to $34 million from the amortization of certain existing regulatory balances in Oregon to offset the accelerated depreciation of certain retired wind equipment, partially offset by lower wholesale volumes. Retail customer volumes decreased 1.4% primarily due to the impacts of COVID-19, which resulted in lower industrial and commercial customer usage and higher residential customer usage, partially offset by an increase in the average number of residential and commercial customers and the favorable impact of weather.

Earnings decreased $32 million for 2020 compared to 2019, primarily due to an increase in operations and maintenance expense due to higher costs associated with wildfires and the Klamath Hydroelectric Settlement Agreement of $169 million, higher interest expense of $25 million from higher long-term debt balances, higher pension and other postretirement costs of $13 million, lower interest income from lower average interest rates and higher property taxes of $10 million, partially offset by lower tax expense from higher PTCs recognized of $62 million from repowered and new wind-powered generating facilities, higher utility margin of $47 million and higher allowances for equity and borrowed funds used during construction of $38 million. Utility margin increased primarily due to lower coal-fueled and natural gas-fueled generation costs, lower purchased power costs and price impacts from changes in sales mix, partially offset by lower net deferrals of incurred net power costs in accordance with established adjustment mechanisms and lower retail customer volumes.

MidAmerican Funding

Operating revenue increased $819 million for 2021 compared to 2020, primarily due to higher natural gas operating revenue of $430 million and higher electric operating revenue of $390 million. Natural gas operating revenue increased due to a higher average per-unit cost of natural gas sold resulting in higher purchased gas adjustment recoveries of $440 million (fully offset in cost of sales), largely due to the February 2021 polar vortex weather event. Electric operating revenue increased due to higher retail revenue of $198 million and higher wholesale and other revenue of $192 million. Electric retail revenue increased primarily due to higher recoveries through adjustment clauses of $116 million (fully offset in expense, primarily cost of sales), higher customer volumes of $63 million and price impacts of $19 million from changes in sales mix. Electric retail customer volumes increased 5.8% due to increased usage of certain industrial customers and the favorable impact of weather. Electric wholesale and other revenue increased primarily due to higher average wholesale prices of $116 million and higher wholesale volumes of $71 million.

Earnings increased $65 million for 2021 compared to 2020, primarily due to higher electric utility margin of $190 million and a favorable income tax benefit, partially offset by higher depreciation and amortization expense of $198 million, higher operations and maintenance expense of $20 million and lower allowances for equity and borrowed funds of $8 million. Electric utility margin increased primarily due to the higher retail and wholesale revenues, partially offset by higher thermal generation and purchased power costs. The favorable income tax benefit was largely due to higher PTCs recognized of $64 million, from new wind-powered generating facilities placed in-service, partially offset by state income tax impacts. The increase in depreciation and amortization expense was primarily due to the impacts of certain regulatory mechanisms and additional assets placed in-service. Operations and maintenance expense increased primarily due to higher costs associated with additional wind-powered generating facilities placed in-service and higher natural gas distribution costs, partially offset by 2020 costs associated with storm restoration activities.

Operating revenue decreased $199 million for 2020 compared to 2019, primarily due to lower natural gas operating revenue of $77 million, lower electric operating revenue of $70 million, lower electric and natural gas energy efficiency program revenue of $38 million (fully offset in operations and maintenance expense) and lower other revenue of $14 million, primarily from nonregulated utility construction services. Natural gas operating revenue decreased primarily due to lower volumes and a lower average per-unit cost of natural gas sold resulting in lower purchased gas adjustment recoveries of $68 million (fully offset in cost of sales) and a 10.2% decrease in retail customer volumes, primarily due to the unfavorable impact of weather. Electric operating revenue decreased due to lower wholesale and other revenue of $88 million, partially offset by higher retail revenue of $18 million. Electric wholesale and other revenue decreased mainly due to lower average wholesale prices of $115 million, partially offset by higher wholesale volumes of $28 million. Electric retail revenue increased primarily due to higher customer usage of $38 million, partially offset by price impacts of $18 million from changes in sales mix. Electric retail customer volumes increased 1.2% due to increased usage for certain industrial customers, partially offset by the impacts of COVID-19, which resulted in lower commercial and industrial customer usage and higher residential customer usage.

Earnings increased $37 million for 2020 compared to 2019, primarily due to higher income tax benefit of $197 million from higher PTCs recognized of $132 million and the favorable impacts of ratemaking, partially offset by higher depreciation and amortization expense of $77 million due to additional assets placed in-service (offset by $23 million of lower Iowa revenue sharing accruals), lower allowances for equity and borrowed funds used during construction of $45 million, higher interest expense of $20 million and lower electric and natural gas utility margins. PTCs recognized increased due to higher wind-powered generation driven primarily by repowering and new wind projects placed in-service. Electric utility margin decreased due to lower wholesale revenue and the price impacts from changes in sales mix, partially offset by lower generation costs from higher wind generation and higher retail customer volumes. Natural gas utility margin decreased primarily due to lower retail customer volumes primarily due to the unfavorable impact of weather.

NV Energy

Operating revenue increased $253 million for 2021 compared to 2020, primarily due to higher electric operating revenue of $252 million. Electric operating revenue increased primarily due to higher fully-bundled energy rates (fully offset in cost of sales) of $229 million, a $120 million one-time bill credit in the fourth quarter of 2020 resulting from a regulatory rate review decision (fully offset in operations and maintenance and income tax expenses) and higher retail customer volumes of $10 million, partially offset by lower base tariff general rates of $71 million at Nevada Power and a favorable regulatory decision in 2020. Electric retail customer volumes increased 3.3%, primarily due to an increase in the average number of customers, higher customer usage and the favorable impact of weather.

Earnings increased $29 million for 2021 compared to 2020, primarily due to lower operations and maintenance expense of $90 million, lower income tax expense mainly from the impacts of ratemaking, lower interest expense of $21 million, higher interest and dividend income of $16 million and lower pension expense of $10 million, partially offset by lower electric utility margin of $97 million and higher depreciation and amortization expense of $47 million. Operations and maintenance expense decreased primarily due to lower regulatory deferrals and amortizations and lower earnings sharing at the Nevada Utilities. Electric utility margin decreased primarily due to lower base tariff general rates at Nevada Power and a favorable regulatory decision in 2020, partially offset by higher retail customer volumes. The increase in depreciation and amortization expense was mainly due to the regulatory amortization of decommissioning costs and additional assets placed in-service.

Operating revenue decreased $183 million for 2020 compared to 2019, primarily due to lower electric operating revenue. Electric operating revenue decreased primarily due to lower fully-bundled energy rates (fully offset in cost of sales) of $164 million and a $120 million one-time bill credit in the fourth quarter of 2020 resulting from a regulatory rate review decision (fully offset in operations and maintenance and income tax expenses), partially offset by higher retail customer volumes, price impacts from changes in sales mix and a favorable regulatory decision. Electric retail customer volumes, including distribution only service customers, increased 1.5%, primarily due to the favorable impact of weather, largely offset by the impacts of COVID-19, which resulted in lower industrial, distribution only service and commercial customer usage and higher residential customer usage.

Earnings increased $45 million for 2020 compared to 2019, primarily due to higher electric utility margin of $100 million, lower pension and post-retirement costs of $9 million and lower income tax expense mainly from the favorable impacts of ratemaking, partially offset by an increase in operations and maintenance expense, mainly from higher earnings sharing accruals at the Nevada Utilities, and higher depreciation and amortization expense of $20 million, mainly from higher plant placed in-service. Electric utility margin increased primarily due to higher retail customer volumes, price impacts from changes in sales mix and a favorable regulatory decision.

Northern Powergrid

Operating revenue increased $166 million for 2021 compared to 2020, primarily due to higher distribution revenue of $80 million, mainly from increased tariff rates of $40 million and a 3.2% increase in units distributed totaling $26 million, and $77 million from the weaker United States dollar.

Earnings increased $46 million for 2021 compared to 2020, primarily due to the higher distribution revenue, lower write-offs of gas exploration costs of $36 million, $16 million from the weaker United States dollar, favorable pension expense of $14 million and lower interest expense of $8 million, partially offset by higher income tax expense and higher distribution-related operating and depreciation expenses of $29 million. Earnings in 2021 included 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, while earnings in 2020 included a deferred income tax charge of $35 million related to a July 2020 enacted increase in the United Kingdom corporate income tax rate from 17% to 19% effective April 1, 2020.

Operating revenue increased $9 million for 2020 compared to 2019, primarily due to higher distribution revenue of $10 million from increased tariff rates of $40 million, partially offset by a 5.4% decrease in units distributed totaling $30 million largely due to the impacts of COVID-19.

Earnings decreased $55 million for 2020 compared to 2019, primarily due to write-offs of gas exploration costs of $44 million, higher income tax expense of $37 million and higher distribution-related operating and depreciation expenses of $18 million, partially offset by higher distribution revenue, lower pension expense of $22 million, including lower pension settlement losses recognized in 2020 compared to 2019, and lower interest expense of $9 million. The increase in income tax expense is due to a change in the United Kingdom corporate income tax rate that resulted in a deferred income tax charge of $35 million.

BHE Pipeline Group

Operating revenue increased $1,966 million for 2021 compared to 2020, primarily due to $1,828 million of incremental revenue at BHE GT&S, acquired in November 2020, higher gas sales of $115 million ($38 million largely offset in costs of sales) at Northern Natural Gas and higher transportation revenue of $29 million at Kern River largely due to higher rates and volumes, partially offset by lower transportation revenue of $24 million at Northern Natural Gas primarily due to lower volumes. The variances in gas sales and transportation revenue at Northern Natural Gas included favorable impacts of $77 million and $49 million, respectively, from the February 2021 polar vortex weather event.

Earnings increased $279 million for 2021 compared to 2020, primarily due to $244 million of incremental earnings at BHE GT&S, favorable earnings of $19 million at Kern River from the higher transportation revenue and higher earnings of $15 million at Northern Natural Gas, primarily due to higher gross margin on gas sales and higher transportation revenue, each due to the favorable impacts of the February 2021 polar vortex weather event, offset by the lower transportation revenue.

Operating revenue increased $447 million for 2020 compared to 2019, primarily due to $331 million of incremental revenue at BHE GT&S, a favorable rate case settlement at Northern Natural Gas of $101 million and higher transportation revenue of $43 million, partially offset by lower gas sales at Northern Natural Gas of $23 million related to system balancing activities (largely offset in cost of sales).

Earnings increased $106 million for 2020 compared to 2019, primarily due to $73 million of incremental earnings BHE GT&S, the higher transportation revenue, and a favorable after-tax, rate case settlement at Northern Natural Gas of $32 million, partially offset by higher property and other tax expense of $17 million, including a non-recurring property tax refund in 2019, higher depreciation and amortization expense of $13 million due to increased spending on capital projects and lower interest income of $9 million.

BHE Transmission

Operating revenue increased $72 million for 2021 compared to 2020, primarily due to $47 million from the stronger United States dollar, a regulatory decision received in November 2020 at AltaLink and higher revenue from the Montana-Alberta Tie Line of $11 million.

Earnings increased $16 million for 2021 compared to 2020, primarily due to $12 million from the stronger United States dollar, higher earnings from the Montana-Alberta Tie Line and lower non-regulated interest expense at BHE Canada, partially offset by the impact of a regulatory decision received in April 2020 at AltaLink.

Operating revenue decreased $48 million for 2020 compared to 2019, primarily due to a regulatory decision received in November 2020 at AltaLink and the stronger United States dollar of $7 million.

Earnings increased $2 million for 2020 compared to 2019, primarily due to lower non-regulated interest expense at BHE Canada and higher net income at BHE U.S. Transmission of $6 million mainly due to improved equity earnings from ETT, partially offset by the impacts of regulatory decisions received in 2020 and 2019 at AltaLink.

BHE Renewables

Operating revenue increased $45 million for 2021 compared to 2020, primarily due to higher natural gas, solar, wind and hydro revenues from favorable market conditions and higher generation, partially offset by an unfavorable change in the valuation of a power purchase agreement of $30 million.

Earnings decreased $70 million for 2021 compared to 2020, primarily due to lower wind earnings of $83 million, largely from lower tax equity investment earnings of $90 million, and lower hydro earnings of $10 million, mainly due to lower income from a declining financial asset balance, partially offset by higher solar earnings of $22 million, mainly due to the higher operating revenue and lower depreciation expense. Tax equity investment earnings decreased due to unfavorable results from existing tax equity investments of $165 million, primarily due to the February 2021 polar vortex weather event, and lower commitment fee income, partially offset by $87 million of earnings from projects reaching commercial operation.

Operating revenue increased $4 million for 2020 compared to 2019, primarily due to higher natural gas, solar and hydro revenues of $21 million due to favorable generation, partially offset by an unfavorable change in the valuation of a power purchase agreement of $14 million and lower geothermal revenues of $4 million from lower pricing.

Earnings increased $90 million for 2020 compared to 2019, primarily due to favorable wind tax equity investment earnings of $129 million, partially offset by lower geothermal earnings of $22 million, due to higher operations and maintenance expense and lower pricing, and lower natural gas earnings of $17 million, due to lower margins. Wind tax equity investment earnings improved due to $147 million of earnings from projects reaching commercial operation, partially offset by lower commitment fee income and lower earnings from existing tax equity investments of $6 million.

HomeServices

Operating revenue increased $819 million for 2021 compared to 2020, primarily due to higher brokerage revenue of $951 million, partially offset by lower mortgage revenue of $169 million from an 8% decrease in funded volume due to a decrease in refinance activity. The increase in brokerage revenue was due to a 21% increase in closed transaction volume at existing companies resulting from increases in average sales price and closed units.

Earnings increased $12 million for 2021 compared to 2020, primarily due to higher earnings from brokerage and franchise services of $81 million, largely attributable to the increase in closed transaction volume at existing companies, partially offset by lower earnings from mortgage services of $68 million from the decrease in refinance activity.

Operating revenue increased $923 million for 2020 compared to 2019, primarily due to higher brokerage revenue of $440 million from a 13% increase in closed transaction volume and higher mortgage revenue of $423 million from a 71% increase in funded mortgage volume due to an increase in refinance activity.

Earnings increased $215 million for 2020 compared to 2019, primarily due to higher earnings at mortgage services of $138 million and higher earnings at brokerage services largely attributable to the favorable interest rate environment.

BHE and Other

Operating revenue increased $103 million for 2021 compared to 2020, primarily due to higher electricity and natural gas sales revenue at MES, from favorable pricing offset by lower volumes.

Earnings decreased $1,773 million for 2021 compared to 2020, primarily due to the $1,693 million change in the after-tax unrealized position of the Company's investment in BYD Company Limited, $95 million of higher dividends on BHE's 4.00% Perpetual Preferred Stock issued in October 2020, higher corporate costs and higher BHE corporate interest expense from debt issuances in March and October 2020, partially offset by favorable comparative consolidated state income tax benefits and higher earnings of $17 million at MES.

Operating revenue decreased $118 million for 2020 compared to 2019, primarily due to lower electricity and natural gas sales revenue at MES, from lower volumes.

Earnings increased $3,559 million for 2020 compared to 2019, primarily due to the $3,697 million change in the after-tax unrealized position of the Company's investment in BYD Company Limited, partially offset by higher BHE corporate interest expense from debt issuances in March and October 2020 and unfavorable comparative consolidated state income tax benefits.

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, 2021, the Company's total net liquidity was as follows (in millions):

	BHE	PacifiCorp	MidAmerican Funding	NV Energy	Northern Powergrid	BHE Canada	BHE Pipeline Group, HomeServices and Other	Total
Cash and cash equivalents	$ 18	$ 179	$ 233	$ 42	$ 39	$ 75	$ 510	$ 1,096
Credit facilities[(1)]	3,500	1,200	1,509	650	271	851	3,300	11,281
Less:								
Short-term debt	—	—	—	(339)	(1)	(245)	(1,424)	(2,009)
Tax-exempt bond support and letters of credit	—	(218)	(370)	—	—	(1)	—	(589)
Net credit facilities	3,500	982	1,139	311	270	605	1,876	8,683
Total net liquidity	$3,518	$ 1,161	$ 1,372	$ 353	$ 309	$ 680	$ 2,386	$ 9,779
Credit facilities:								
Maturity dates	2024	2024	2022, 2024	2024	2024	2022, 2026	2022, 2026	

(1) Includes drawn uncommitted credit facilities totaling $1 million at Northern Powergrid.

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

Operating Activities

Net cash flows from operating activities for the years ended December 31, 2021 and 2020 were $8.7 billion and $6.2 billion, respectively. The increase was primarily due to $970 million of incremental net cash flows from operating activities at BHE GT&S, improved operating results and changes in working capital.

Net cash flows from operating activities for the years ended December 31, 2020 and 2019 were $6,224 million and $6,206 million, respectively. The increase was primarily due to an increase in income tax receipts and improved operating results, partially offset by changes in working capital.

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

Investing Activities

Net cash flows from investing activities for the years ended December 31, 2021 and 2020 were $(5.8) billion and $(13.2) billion, respectively. The change was primarily due to lower funding of tax equity investments, lower cash paid for acquisitions and the July 2021 receipt of $1.3 billion due to the termination of the Q-Pipe Purchase Agreement. Refer to "Future Uses of Cash" for further discussion of capital expenditures.

Net cash flows from investing activities for the years ended December 31, 2020 and 2019 were $(13.2) billion and $(9.0) billion, respectively. The change was primarily due to higher cash paid for acquisitions and higher funding of tax equity investments, partially offset by lower capital expenditures of $599 million. Refer to "Future Uses of Cash" for further discussion of capital expenditures.

Natural Gas Transmission and Storage Business Acquisition

On November 1, 2020, BHE completed its acquisition of substantially all of the natural gas transmission and storage business of DEI and Dominion Questar, exclusive of the Questar Pipeline Group (the "GT&S Transaction"). Under the terms of the Purchase and Sale Agreement, dated July 3, 2020 (the "GT&S Purchase Agreement"), BHE paid approximately $2.5 billion in cash, after post-closing adjustments (the "GT&S Cash Consideration"), and assumed approximately $5.6 billion of existing indebtedness for borrowed money, including fair value adjustments.

On October 5, 2020, DEI and Dominion Questar, as permitted under the terms of the GT&S Purchase Agreement, delivered notice to BHE of their election to terminate the GT&S Transaction with respect to the Questar Pipeline Group and, in connection with the execution of the Q-Pipe Purchase Agreement referenced below, to waive the related termination fee under the GT&S Purchase Agreement. Also on October 5, 2020, BHE entered into a second Purchase and Sale Agreement (the "Q-Pipe Purchase Agreement") with Dominion Questar providing for BHE's purchase of the Questar Pipeline Group from Dominion Questar (the "Q-Pipe Transaction") after receipt of HSR Approval for a cash purchase price of approximately $1.3 billion (the "Q-Pipe Cash Consideration"), subject to adjustment for cash and indebtedness as of the closing, and the assumption of approximately $430 million of existing indebtedness for borrowed money. Under the Q-Pipe Purchase Agreement, BHE delivered the Q-Pipe Cash Consideration of approximately $1.3 billion to Dominion Questar on November 2, 2020.

On July 9, 2021, Dominion Questar and DEI delivered a written notice to BHE stating that BHE and Dominion Questar have mutually elected to terminate the Q-Pipe Purchase Agreement. On July 14, 2021, BHE received the Purchase Price Repayment Amount of approximately $1.3 billion in cash.

Financing Activities

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.

Net cash flows from financing activities for the year ended December 31, 2020 were $7.1 billion. Sources of cash totaled $11.7 billion and consisted of proceeds from BHE senior debt issuances of $5.2 billion, proceeds from preferred stock issuances of $3.8 billion and proceeds from subsidiary debt issuances totaling $2.7 billion. Uses of cash totaled $4.5 billion and consisted mainly of $2.8 billion for repayments of subsidiary debt, net repayments of short-term debt of $939 million and $350 million for repayments of BHE senior debt.

Net cash flows from financing activities for the year ended December 31, 2019 were $3.1 billion. Sources of cash totaled $5.4 billion and consisted of proceeds from subsidiary debt issuances totaling $4.7 billion and net proceeds from short-term debt of $684 million. Uses of cash totaled $2.3 billion and consisted mainly of $1.9 billion for repayments of subsidiary debt and repurchases of common stock of $293 million.

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 Issuance

On October 29, 2020, BHE issued $3.75 billion of its 4.00% Perpetual Preferred Stock to certain subsidiaries of Berkshire Hathaway Inc. in order to fund the GT&S Cash Consideration and the Q-Pipe Cash Consideration.

Preferred Stock Redemptions

For the year ended December 31, 2021, BHE redeemed at par 2,100,012 shares of its 4.00% Perpetual Preferred Stock from certain subsidiaries of Berkshire Hathaway Inc. for $2.1 billion.

Common Stock Transactions

For the years ended December 31, 2020 and 2019, BHE repurchased 180,358 shares of its common stock for $126 million and 447,712 shares of its common stock for $293 million, respectively.

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		
	2019	**2020**	**2021**	**2022**	**2023**	**2024**
PacifiCorp	$ 2,175	$ 2,540	$ 1,513	$ 2,001	$ 3,317	$ 2,501
MidAmerican Funding	2,810	1,836	1,912	1,913	2,650	2,311
NV Energy	657	675	749	1,480	1,839	2,087
Northern Powergrid	602	682	742	677	633	632
BHE Pipeline Group	687	659	1,128	1,064	987	981
BHE Transmission	247	372	279	220	226	309
BHE Renewables	122	95	225	109	371	198
HomeServices	54	36	42	62	41	40
BHE and Other[1]	10	(130)	21	24	3	4
Total	$ 7,364	$ 6,765	$ 6,611	$ 7,550	$ 10,067	$ 9,063

(1) BHE and Other includes intersegment eliminations.

	Historical			Forecast		
	2019	2020	2021	2022	2023	2024
Wind generation	$ 2,828	$ 2,125	$ 1,339	$ 1,010	$ 2,590	$ 2,283
Electric distribution	1,537	1,719	1,694	1,696	1,723	1,556
Electric transmission	1,070	958	813	1,624	2,380	1,985
Natural gas transmission and storage	717	640	1,068	908	882	879
Solar generation	5	16	157	189	760	949
Other	1,207	1,307	1,540	2,123	1,732	1,411
Total	$ 7,364	$ 6,765	$ 6,611	$ 7,550	$ 10,067	$ 9,063

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

- Wind generation includes both growth and operating expenditures. Growth expenditures include spending for the following:
    - Construction and acquisition of wind-powered generating facilities at MidAmerican Energy totaling $540 million for 2021, $848 million for 2020 and $1,486 million for 2019. MidAmerican Energy placed in-service 294 MWs during 2021, 729 MWs during 2020, including the acquisition of an existing 80-MW wind farm and 1,019 MWs during 2019. All of these wind-powered generating facilities placed in-service in 2021, 2020 and 2019 qualify for 100% of PTCs available. PTCs from these projects are excluded from MidAmerican Energy's Iowa EAC until these generation assets are reflected in base rates. Planned spending for the construction of wind-powered generating facilities totals $190 million in 2022, $1,744 million in 2023 and $1,678 million in 2024.
    - Repowering of wind-powered generating facilities at MidAmerican Energy totaling $354 million for 2021, $37 million for 2020 and $369 million for 2019. Planned spending for repowering totals $509 million in 2022. 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. The rate at which PTCs are re-established for a facility depends upon the date construction begins. Of the 865 MWs of current repowering projects not in-service as of December 31, 2021, 564 MWs are currently expected to qualify for 80% of the PTCs available for 10 years following each facility's return to service and 301 MWs are expected to qualify for 60% of such credits.
    - Construction of wind-powered generating facilities at PacifiCorp totaling $107 million for 2021, $1,148 million for 2020 and $338 million for 2019. Construction includes 674 MWs of new wind-powered generating facilities that were placed in-service in 2020 and 516 MWs that were placed in-service in 2021. Planned spending for the construction of additional wind-powered generating facilities totals $131 million in 2022, $405 million in 2023 and $373 million in 2024. The energy production from the new wind-powered generating facilities placed in-service by the end of 2024 is expected to qualify for 60% of the federal PTCs available for 10 years once the equipment is placed in-service.
    - Repowering of existing wind-powered generating facilities at PacifiCorp totaling $9 million for 2021, $125 million for 2020 and $585 million for 2019. All existing wind-powered generating facilities at PacifiCorp have been repowered as of December 31, 2021.
    - The 2021 IRP also included PacifiCorp's planned acquisition and repowering of two wind-powered generating facilities. The repowered facilities are expected to be placed in-service in 2023 and 2024. PacifiCorp spent $11 million in 2021 and planned spending for acquiring and repowering generating facilities totals $60 million in 2022, $36 million in 2023 and $34 million in 2024.
    - Construction of wind-powered generating facilities at BHE Renewables totaling $155 million for 2021 and $15 million for 2019. 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. Planned spending for future wind generation totals $306 million in 2023 and $102 million in 2024.

- 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, wildfire mitigation, storm damage restoration and repairs and investments in routine expenditures for distribution needed to serve existing and expected demand.
- Electric transmission includes both growth and operating expenditures. Growth expenditures include spending for the following:
  - PacifiCorp's transmission investment in 2021 through 2024 primarily reflecting planned costs for the 416-mile, 500-kV high-voltage transmission line between the Aeolus substation near Medicine Bow in 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. PacifiCorp is advancing permitting and regulatory approvals related to the projects. Planned spending for these Energy Gateway Transmission segments to be placed in-service in 2024-2026 totals $565 million in 2022, $1,143 million in 2023 and $437 million in 2024.
  - Nevada Utilities' Greenlink Nevada transmission expansion program. In this project, the company has received approval from the PUCN to build a 350-mile, 525-kV transmission line, known as Greenlink West, connecting the Ft. Churchill substation to the Northwest substation to the Harry Allen substation; a 235-mile, 525-kV transmission line, known as Greenlink North, connecting the new Ft. Churchill substation to the Robinson Summit substation; a 46-mile, 345-kV transmission line from the new Ft. Churchill substation to the Mira Loma substations; and a 38-mile, 345-kV transmission line from the new Ft. Churchill substation to the Robinson Summit substations. Planned spending for the expansion programs estimated to be placed in-service in 2026-2028 totals $61 million in 2022, $148 million in 2023 and $498 million in 2024.
  - 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.
- Natural gas transmission and storage includes both growth and operating expenditures. Growth expenditures include, among other items, spending for the Northern Natural Gas Twin Cities Area Expansion and Spraberry Compression projects. Operating expenditures include, among other items, spending for asset modernization, pipeline integrity projects and natural gas transmission, storage and LNG terminalling infrastructure needs to serve existing and expected demand.
- Solar generation includes growth expenditures, including spending for the following:
  - Construction of solar-powered generating facilities at MidAmerican Energy totaling 141 MWs of small- and utility-scale solar generation, with total spend of $132 million in 2021 and planned spending of $93 million in 2022 and $58 million in 2023.
  - Construction of solar-powered generating facilities at the Nevada Utilities' includes expenditures for three solar photovoltaic facilities, including 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 the end of 2023; a 250 MW solar photovoltaic facility with an additional 200 MWs of co-located battery storage that will be developed in Humboldt County, Nevada, with commercial operation expected by the end of 2023; and a 350 MW solar photovoltaic facility with an additional 280 MWs of co-located battery storage that will be developed in Humboldt County, Nevada, with commercial operation expected by the end of 2024. The facilities located in Humboldt County will be jointly owned and operated by Nevada Power and Sierra Pacific. Planned spending totals $702 million in 2023 and $799 million in 2024.
  - 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 by November 30, 2024. Planned spending totals $150 million in 2024.
- 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, 2021, the Company's investments that are accounted for under the equity method had short- and long-term debt of $2.7 billion, unused revolving credit facilities of $200 million and letters of credit outstanding of $88 million. As of December 31, 2021, the Company's pro-rata share of such short- and long-term debt was $1.3 billion, unused revolving credit facilities was $100 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 $32.4 billion on long-term debt, including $2.1 billion due in 2022.

Additionally, 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 has made contributions of $— million, $2,736 million and $1,619 million in 2021, 2020 and 2019, respectively, and has commitments as of December 31, 2021, subject to satisfaction of certain specified conditions, to provide equity contributions of $356 million in 2022 pursuant to these equity capital contribution agreements as the various projects achieve commercial operation. However, the Company expects to assign its rights and obligations under these equity capital contribution agreements, including any related funding commitments, to an entity affiliated through common ownership. 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.

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 Corp. ("Constellation Energy," previously Exelon Generation Company, LLC, which was a subsidiary of Exelon Corporation prior to February 1, 2022), the operator of Quad Cities Generating Station Units 1 and 2 ("Quad Cities Station") of which MidAmerican Energy has a 25% ownership interest, announced on June 2, 2016, its intention to shut down Quad Cities Station on June 1, 2018. 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. The proceeds from the ZECs will provide Constellation Energy additional revenue through 2027 as an incentive for continued operation of Quad Cities Station. MidAmerican Energy will 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, 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-fired resources. An expanded PJM MOPR to include existing resources would require exclusion of ZEC compensation when bidding into future capacity auctions, resulting in an increased risk of Quad Cities Station not receiving capacity revenues in future auctions.

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 in May 2021. While the FERC included some limited exemptions, no exemptions were available to state-supported nuclear resources, such as Quad Cities Station. The FERC provided no new mechanism for accommodating state-supported resources 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. In response to the FERC's order, the PJM submitted a compliance filing on March 18, 2020, wherein the PJM proposed tariff language reflecting the FERC's directives and a schedule for resuming capacity auctions. On April 16, 2020, the FERC issued an order largely denying requests for rehearing of the FERC's December 2019 order but granting a few clarifications that required an additional PJM compliance filing, which the PJM submitted on June 1, 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 D.C. Circuit.

As a result, the MOPR applied to Quad Cities Station in the capacity auction for the 2022-2023 planning year, 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 at 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 will no longer apply to Quad Cities Station. 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. Constellation Energy is strenuously opposing these appeals.

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's December 19, 2019 order on the PJM MOPR may undermine the continued effectiveness of the Illinois zero emission standard 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 climate change, RPS, air and water quality, emissions performance standards, coal combustion byproduct disposal, hazardous and solid waste disposal, protected species 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, local and international agencies. The Company 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. 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, 2021, 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, 2021, the Company would have been required to post $460 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 United States and Canada, the Regulated Businesses operate under cost-of-service based rate structures administered by various state and provincial commissions and the FERC. Under these rate 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.

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 the 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 $4.0 billion and total regulatory liabilities were $7.2 billion as of December 31, 2021. 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, 2021 includes goodwill of acquired businesses of $11.7 billion. The Company evaluates goodwill for impairment at least annually and completed its annual review as of October 31. Additionally, no indicators of impairment were identified as of December 31, 2021. 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 substantially 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 the asset that are used in the impairment analysis requires judgment regarding what the Company would expect to recover from the future use of the asset. Changes in judgment that could significantly alter the calculation of the fair value or the recoverable amount of the asset may result from significant changes in the regulatory environment, the business climate, management's plans, legal factors, market price of the asset, the use of the asset or 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, 2021, the Company recognized a net asset totaling $433 million for the funded status of the defined benefit pension and other postretirement benefit plans. As of December 31, 2021, amounts not yet recognized as a component of net periodic benefit cost that were included in net regulatory assets totaled $297 million and in AOCI totaled $428 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 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 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, 2021.

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 2025, 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 the 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, 2021						
Benefit Obligations:						
Discount rate	$ (136)	$ 153	$ (33)	$ 37	$ (162)	$ 189
Effect on 2021 Periodic Cost:						
Discount rate	$ —	$ 5	$ 1	$ —	$ (20)	$ 23
Expected rate of return on plan assets	(13)	13	(4)	4	(12)	12

A variety of factors affect the funded status of the plans, including asset returns, discount rates, 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, if any, 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 continue to pass income tax benefits and expense related to the federal tax rate change from 35% to 21% as a result of 2017 Tax Reform, certain property-related basis differences and other various differences on to their customers. As of December 31, 2021, these amounts were recognized as a net regulatory liability of $2.8 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 United States but the tax is not expected to be material.

Revenue Recognition - Unbilled Revenue

Revenue recognized is equal to what the Company has the right to invoice as it corresponds directly with the value to the customer of the Company's performance to date and includes billed and unbilled amounts. The determination of customer invoices is based on a systematic reading of meters, fixed reservation charges based on contractual quantities and rates or, in the case of the Great Britain distribution businesses, when information is received from the national settlement system. 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. Unbilled revenue was $718 million as of December 31, 2021. 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.

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 business platforms has established guidelines for credit risk management.

<u>Commodity Price Risk</u>

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 $26 million and $35 million, respectively, as of December 31, 2021 and 2020, 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, 2021:			
Not designated as hedging contracts	$ 20	$ 116	$ (76)
Designated as hedging contracts	(10)	(5)	(15)
Total commodity derivative contracts	$ 10	$ 111	$ (91)
As of December 31, 2020:			
Not designated as hedging contracts	$ 103	$ 143	$ 63
Designated as hedging contracts	(4)	10	(18)
Total commodity derivative contracts	$ 99	$ 153	$ 45

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, 2021 and 2020, a net regulatory asset of $71 million and a net regulatory liability of $16 million, respectively, was recorded related to the net derivative asset of $20 million and $103 million, respectively. The difference between the net regulatory asset and the net derivative asset relates primarily to a power purchase agreement derivative at BHE Renewables. 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, 2021 and 2020, the Company had short- and long-term variable-rate obligations totaling $3.7 billion and $4.4 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, 2021 and 2020.

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, 2021 and 2020, the Company had variable-to-fixed interest rate swaps with notional amounts of $533 million and $1,083 million, respectively, and £174 million and £121 million, respectively, to protect the Company against an increase in interest rates. Additionally, as of December 31, 2021 and 2020, the Company had mortgage commitments, net, with notional amounts of $1,512 million and $1,636 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 $16 million as of December 31, 2021 and a net derivative liability of $3 million as of December 31, 2020. 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, 2021, 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 as of December 31.

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, 2021 and 2020, the Company's investment in BYD Company Limited common stock represented approximately 92% and 91%, 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, 2021 and 2020 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, 2021	$ 7,693	30% increase	$ 10,001	3 %
		30% decrease	5,385	(3)
As of December 31, 2020	$ 5,897	30% increase	$ 7,666	2 %
		30% decrease	4,128	(2)

Foreign Currency Exchange Rate Risk

BHE's business operations and investments outside of the United States 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 United States 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, 2021, a 10% devaluation in the British pound to the United States dollar would result in the Company's Consolidated Balance Sheet being negatively impacted by a $506 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 $25 million in 2021.

BHE Canada's functional currency is the Canadian dollar. As of December 31, 2021, a 10% devaluation in the Canadian dollar to the United States dollar would result in the Company's Consolidated Balance Sheet being negatively impacted by a $384 million cumulative translation adjustment in AOCI. A 10% devaluation in the average currency exchange rate would have resulted in lower reported earnings for BHE Canada of $19 million in 2021.

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, 2021, 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, 2021, MidAmerican Energy's aggregate direct credit exposure from electric wholesale marketing counterparties was not material.

As of December 31, 2021, 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 2021, E.ON and certain of its affiliates and British Gas Trading Limited represented approximately 23% and 12%, 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 $719 million for the year ended December 31, 2021.

BHE Renewables

BHE Renewables owns independent power projects that generally have separate project financing agreements. These projects source of operating revenue is derived primarily from long-term power purchase agreements with single customers, primarily utilities, which expire between 2023 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 was $981 million for the year ended December 31, 2021.

Other Energy Business

MES is exposed to counterparty credit risk associated with wholesale energy supply and marketing activities with financial institutions and other market participants. Credit risk may be concentrated to the extent that MES' counterparties have similar economic, industry or other characteristics and due to direct or indirect relationships among the counterparties. Before entering into a transaction, MES 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, MES 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, MES exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

As of December 31, 2021, MES' aggregate credit exposure from energy related transactions, based on settlement and mark-to-market exposures, net of collateral, was not material.

Item 8. Financial Statements and Supplementary Data

Report of Independent Registered Public Accounting Firm	125
Consolidated Balance Sheets	128
Consolidated Statements of Operations	130
Consolidated Statements of Comprehensive Income	131
Consolidated Statements of Changes in Equity	132
Consolidated Statements of Cash Flows	133
Notes to Consolidated Financial Statements	134

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, 2021 and 2020, 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, 2021, 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, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021, 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 audit 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 a separate opinion on the critical audit matters or on the accounts or disclosures to which they relate.

Regulatory Matters — Impact of Rate Regulation on the Financial Statements — Refer to Notes 2 and 7 to the financial statements

Critical Audit Matter Description

The Company, through its regulated businesses, 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 the Company's regulated businesses in the respective service territories where the Company operates. Management has determined it meets 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 impacts multiple financial statement line items and disclosures, such as property, plant and equipment, net; regulatory assets and liabilities; deferred income taxes; operating revenue; operations and maintenance expense; depreciation and amortization expense and income tax expense (benefit).

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 impact 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 their costs.

We identified the impact of rate regulation as a critical audit matter due to the significant judgments made by management to support its assertions about impacted account balances and disclosures and the high degree of subjectivity involved in assessing the impact of future 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 future 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 the Company's disclosures related to the impacts of rate regulation, including the balances recorded and regulatory developments.
- We read relevant regulatory orders issued by the Commissions, regulatory statutes, interpretations, procedural memorandums, filings made by interveners, and other publicly available information 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 evaluated the external information and compared to management's recorded regulatory asset and liability balances for completeness.
- For regulatory matters in process, we inspected the Company's filings with the Commissions and the filings with the Commissions by intervenors that may impact the Company's future rates, for any evidence that might contradict management's assertions.
- 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.

California and Oregon 2020 Wildfires — Contingencies — See Note 16 to the financial statements

Critical Audit Matter Description

The Company has loss contingencies related to the California and Oregon 2020 wildfires (the "2020 wildfires"). The Company has recorded estimated liabilities, net of expected insurance recoveries, of $136 million as of December 31, 2021, which represents its best estimate of probable losses, net of expected insurance recoveries, as a result of the 2020 wildfires.

We identified wildfire-related contingencies and the related disclosure as a critical audit matter because of the significant judgments made by management to estimate the losses. This required the application of a high degree of judgment and extensive effort when performing audit procedures to evaluate the reasonableness of management's estimate of the losses and disclosure related to wildfire-related loss contingencies.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to management's judgments regarding its estimate of losses for wildfire-related contingencies and the related disclosure included the following, among others:

- We evaluated management's judgments related to whether a loss was probable and reasonably estimable, reasonably possible, or remote for each individual wildfire by inquiring of management and the Company's external and internal legal counsel regarding the amounts of probable and reasonably estimable, reasonably possible, and remote losses, including the potential impact of information gained through management's and its external and internal legal counsel's ongoing investigations into the causes of each fire, and external information for any evidence that might contradict management's assertions.
- We evaluated the estimation methodology for determining the amount of probable loss through inquiries with management and its external and internal legal counsel.
- We tested the significant assumptions used in determining the estimate, including, but not limited to, information gained through management's and its external and internal legal counsel's ongoing investigations into the causes of each fire.
- We read legal letters from the Company's external and internal legal counsel regarding information regarding ongoing litigation related to the 2020 wildfires and evaluated whether the information therein was consistent with the information obtained in our procedures.
- We evaluated whether the Company's disclosures were appropriate and consistent with the information obtained in our procedures.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
February 25, 2022

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,	
	2021	**2020**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,096	$ 1,290
Restricted cash and cash equivalents	127	140
Trade receivables, net	2,468	2,107
Inventories	1,122	1,168
Mortgage loans held for sale	1,263	2,001
Regulatory assets	544	283
Other current assets	1,628	2,458
Total current assets	8,248	9,447
Property, plant and equipment, net	89,816	86,128
Goodwill	11,650	11,506
Regulatory assets	3,419	3,157
Investments and restricted cash and cash equivalents and investments	15,788	14,320
Other assets	3,144	2,758
Total assets	$ 132,065	$ 127,316

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,	
	2021	**2020**
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 2,136	$ 1,867
Accrued interest	537	555
Accrued property, income and other taxes	606	582
Accrued employee expenses	372	383
Short-term debt	2,009	2,286
Current portion of long-term debt	1,265	1,839
Other current liabilities	1,837	1,626
Total current liabilities	8,762	9,138
BHE senior debt	13,003	12,997
BHE junior subordinated debentures	100	100
Subsidiary debt	35,394	34,930
Regulatory liabilities	6,960	7,221
Deferred income taxes	12,938	11,775
Other long-term liabilities	4,319	4,178
Total liabilities	81,476	80,339
Commitments and contingencies (Note 16)		
Equity:		
BHE shareholders' equity:		
Preferred stock - 100 shares authorized, $0.01 par value, 2 and 4 shares issued and outstanding	1,650	3,750
Common stock - 115 shares authorized, no par value, 76 shares issued and outstanding	—	—
Additional paid-in capital	6,374	6,377
Long-term income tax receivable	(744)	(658)
Retained earnings	40,754	35,093
Accumulated other comprehensive loss, net	(1,340)	(1,552)
Total BHE shareholders' equity	46,694	43,010
Noncontrolling interests	3,895	3,967
Total equity	50,589	46,977
Total liabilities and equity	$ 132,065	$ 127,316

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,		
	2021	**2020**	**2019**
Operating revenue:			
Energy	$ 18,935	$ 15,556	$ 15,371
Real estate	6,215	5,396	4,473
Total operating revenue	25,150	20,952	19,844
Operating expenses:			
Energy:			
Cost of sales	5,504	4,187	4,586
Operations and maintenance	3,991	3,545	3,318
Depreciation and amortization	3,829	3,410	2,965
Property and other taxes	789	634	574
Real estate	5,710	4,885	4,251
Total operating expenses	19,823	16,661	15,694
Operating income	5,327	4,291	4,150
Other income (expense):			
Interest expense	(2,118)	(2,021)	(1,912)
Capitalized interest	64	80	77
Allowance for equity funds	126	165	173
Interest and dividend income	89	71	117
Gains (losses) on marketable securities, net	1,823	4,797	(288)
Other, net	(17)	88	97
Total other income (expense)	(33)	3,180	(1,736)
Income before income tax (benefit) expense and equity loss	5,294	7,471	2,414
Income tax (benefit) expense	(1,132)	308	(598)
Equity loss	(237)	(149)	(44)
Net income	6,189	7,014	2,968
Net income attributable to noncontrolling interests	399	71	18
Net income attributable to BHE shareholders	5,790	6,943	2,950
Preferred dividends	121	26	—
Earnings on common shares	$ 5,669	$ 6,917	$ 2,950

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,		
	2021	**2020**	**2019**
Net income	$ 6,189	$ 7,014	$ 2,968
Other comprehensive income, net of tax:			
Unrecognized amounts on retirement benefits, net of tax of $55, $(19) and $(15)	174	(65)	(59)
Foreign currency translation adjustment	(24)	234	327
Unrealized gains (losses) on cash flow hedges, net of tax of $10, $(3) and $(8)	67	(15)	(29)
Total other comprehensive income, net of tax	217	154	239
Comprehensive income	6,406	7,168	3,207
Comprehensive income attributable to noncontrolling interests	404	71	18
Comprehensive income attributable to BHE shareholders	$ 6,002	$ 7,097	$ 3,189

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, 2018	$ —	$ —	$ 6,371	$ (457)	$ 25,624	$ (1,945)	$ 130	$ 29,723
Net income	—	—	—	—	2,950	—	18	2,968
Other comprehensive income	—	—	—	—	—	239	—	239
Long-term income tax receivable adjustments	—	—	33	(73)	—	—	—	(40)
Common stock purchases	—	—	(15)	—	(278)	—	—	(293)
Distributions	—	—	—	—	—	—	(22)	(22)
Other equity transactions	—	—	—	—	—	—	3	3
Balance, December 31, 2019	—	—	6,389	(530)	28,296	(1,706)	129	32,578
Net income	—	—	—	—	6,943	—	70	7,013
Other comprehensive income	—	—	—	—	—	154	—	154
Long-term income tax receivable adjustments	—	—	—	(128)	—	—	—	(128)
Issuance of preferred stock	3,750	—	—	—	—	—	—	3,750
Preferred stock dividend	—	—	—	—	(26)	—	—	(26)
Common stock purchases		—	(6)	—	(120)	—	—	(126)
Distributions	—	—	—	—	—	—	(121)	(121)
Purchase of noncontrolling interest	—	—	(5)	—	—	—	(28)	(33)
BHE GT&S acquisition - noncontrolling interest	—	—	—	—	—	—	3,916	3,916
Other equity transactions	—	—	(1)	—	—	—	1	—
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
Purchase of noncontrolling interest	—	—	(3)	—	—	—	(4)	(7)
Other equity transactions	—	—	—	—	—	—	(1)	(1)
Balance, December 31, 2021	$ 1,650	$ —	$ 6,374	$ (744)	$ 40,754	$ (1,340)	$ 3,895	$ 50,589

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,		
	2021	**2020**	**2019**
Cash flows from operating activities:			
Net income	$ 6,189	$ 7,014	$ 2,968
Adjustments to reconcile net income to net cash flows from operating activities:			
(Gains) losses on marketable securities, net	(1,823)	(4,797)	288
Losses on other items, net	112	54	43
Depreciation and amortization	3,881	3,455	3,011
Allowance for equity funds	(126)	(165)	(173)
Equity loss, net of distributions	380	248	93
Changes in regulatory assets and liabilities	(668)	(415)	153
Deferred income taxes and investment tax credits, net	646	1,880	290
Other, net	(169)	(77)	23
Changes in other operating assets and liabilities, net of effects from acquisitions:			
Trade receivables and other assets	553	(1,318)	(372)
Derivative collateral, net	82	43	(25)
Pension and other postretirement benefit plans	(39)	(65)	(51)
Accrued property, income and other taxes, net	(489)	(134)	(16)
Accounts payable and other liabilities	163	501	(26)
Net cash flows from operating activities	8,692	6,224	6,206
Cash flows from investing activities:			
Capital expenditures	(6,611)	(6,765)	(7,364)
Acquisitions, net of cash acquired	(122)	(2,397)	(27)
Purchases of marketable securities	(297)	(370)	(262)
Proceeds from sales of marketable securities	273	325	238
Purchases of other investments	(20)	(1,323)	—
Proceeds from other investments	1,300	13	18
Equity method investments	(212)	(2,724)	(1,617)
Other, net	(74)	76	51
Net cash flows from investing activities	(5,763)	(13,165)	(8,963)
Cash flows from financing activities:			
Proceeds from issuance of preferred stock	—	3,750	—
Preferred stock redemptions	(2,100)	—	—
Preferred dividends	(132)	(7)	—
Common stock purchases	—	(126)	(293)
Proceeds from BHE senior debt	—	5,212	—
Repayments of BHE senior debt	(450)	(350)	—
Proceeds from subsidiary debt	2,409	2,688	4,699
Repayments of subsidiary debt	(2,024)	(2,841)	(1,914)
Net (repayments of) proceeds from short-term debt	(276)	(939)	684
Purchase of noncontrolling interest	—	(33)	—
Distributions to noncontrolling interests	(488)	(122)	(23)
Contributions from noncontrolling interests	9	5	8
Other, net	(79)	(134)	(37)
Net cash flows from financing activities	(3,131)	7,103	3,124
Effect of exchange rate changes	1	15	18
Net change in cash and cash equivalents and restricted cash and cash equivalents	(201)	177	385
Cash and cash equivalents and restricted cash and cash equivalents at beginning of period	1,445	1,268	883
Cash and cash equivalents and restricted cash and cash equivalents at end of period	$ 1,244	$ 1,445	$ 1,268

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 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 ("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 ("BHE Canada") (which primarily consists of AltaLink, L.P. ("AltaLink")) and BHE U.S. Transmission, LLC), BHE Renewables, LLC ("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 United States 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 United States, an electric transmission business in Canada, interests in electric transmission businesses in the United States, a renewable energy business primarily investing in wind, solar, geothermal and hydroelectric projects, the largest residential real estate brokerage firm in the United States and one of the largest residential real estate brokerage franchise networks in the United States.

(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; fair value of assets acquired and liabilities assumed in business combinations; 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

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 in 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 Equivalents and Restricted Cash and Cash Equivalents and Investments

Cash equivalents consist of funds invested in money market mutual funds, United States 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. Restricted amounts are included in restricted cash and cash equivalents and investments and restricted cash and cash equivalents and investments on the Consolidated Balance Sheets.

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 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):

	2021	**2020**	**2019**
Beginning balance	$ 77	$ 44	$ 42
Charged to operating costs and expenses, net	81	56	47
Acquisitions	—	5	—
Write-offs, net	(50)	(28)	(45)
Ending balance	$ 108	$ 77	$ 44

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 $296 million and $382 million as of December 31, 2021 and 2020, respectively, and materials and supplies totaling $826 million and $786 million as of December 31, 2021 and 2020, 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 $27 million and $10 million higher as of December 31, 2021 and 2020, 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

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 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 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. 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 2021, 2020 and 2019, 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 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, 2021 and 2020, trade receivables, net on the Consolidated Balance Sheets relate substantially to Customer Revenue, including unbilled revenue of $718 million and $750 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 United States 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 United States federal and Iowa state income tax returns and the majority of the Company's United States federal income tax is remitted to or received from Berkshire Hathaway. The Company records the deferred income tax assets associated with the state of Iowa net operating loss carryforward as a long-term income tax receivable from Berkshire Hathaway as a component of BHE's shareholders' equity due to the long-term related party nature of the income tax receivable.

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 generally 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.

(3) Business Acquisitions

BHE GT&S Acquisition

Transaction Description

On November 1, 2020, BHE completed its acquisition of substantially all of the natural gas transmission and storage business of Dominion Energy, Inc. ("DEI") and Dominion Energy Questar Corporation ("Dominion Questar"), exclusive of Dominion Energy Questar Pipeline, LLC and related entities (the "Questar Pipeline Group") (the "GT&S Transaction"). Under the terms of the Purchase and Sale Agreement, dated July 3, 2020 (the "GT&S Purchase Agreement"), BHE paid approximately $2.5 billion in cash, after post-closing adjustments (the "GT&S Cash Consideration"), and assumed approximately $5.6 billion of existing indebtedness for borrowed money, including fair value adjustments, for 100% of the equity interests of Eastern Gas Transmission and Storage, Inc. ("EGTS") and Carolina Gas Transmission, LLC; 50% of the equity interests of Iroquois Gas Transmission System L.P. ("Iroquois"); and a 25% economic interest in Cove Point LNG, LP ("Cove Point"), consisting of 100% of the general partnership interest and 25% of the total limited partnership interests. BHE became the operator of Cove Point after the GT&S Transaction. The GT&S Transaction received clearance under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended ("HSR Approval") in October 2020, and approval by the United States Department of Energy with respect to a change in control of Cove Point and the Federal Communications Commission with respect to the transfer of certain licenses earlier in 2020.

On October 5, 2020, DEI and Dominion Questar, as permitted under the terms of the GT&S Purchase Agreement, delivered notice to BHE of their election to terminate the GT&S Transaction with respect to the Questar Pipeline Group and, in connection with the execution of the Q-Pipe Purchase Agreement referenced below, to waive the related termination fee under the GT&S Purchase Agreement. Also on October 5, 2020, BHE entered into a second Purchase and Sale Agreement (the "Q-Pipe Purchase Agreement") with Dominion Questar providing for BHE's purchase of the Questar Pipeline Group from Dominion Questar (the "Q-Pipe Transaction") after receipt of HSR Approval for a cash purchase price of approximately $1.3 billion (the "Q-Pipe Cash Consideration"), subject to adjustment for cash and indebtedness as of the closing, and the assumption of approximately $430 million of existing indebtedness for borrowed money. DEI was also a party to the Q-Pipe Purchase Agreement, as guarantor for certain provisions regarding the Purchase Price Repayment Amount (as defined below) and other matters.

Under the Q-Pipe Purchase Agreement, BHE delivered the Q-Pipe Cash Consideration of approximately $1.3 billion, which was included in other current assets on the Consolidated Balance Sheet as of December 31, 2020, to Dominion Questar on November 2, 2020. Pursuant to the Q-Pipe Purchase Agreement, Dominion Questar agreed that, if the Q-Pipe Transaction did not close, it would repay all or (depending upon the repayment date) substantially all of the Q-Pipe Cash Consideration (the "Purchase Price Repayment Amount") to BHE on or prior to December 31, 2021.

On July 9, 2021, Dominion Questar and DEI delivered a written notice to BHE stating that BHE and Dominion Questar have mutually elected to terminate the Q-Pipe Purchase Agreement. On July 14, 2021, BHE received the Purchase Price Repayment Amount of approximately $1.3 billion in cash, which was included in proceeds from other investments on the Consolidated Statements of Cash Flows for the year ended December 31, 2021.

Included in BHE's Consolidated Statement of Operations within the BHE Pipeline Group reportable segment for the years ended December 31, 2021 and 2020, is operating revenue of $2,159 million and $331 million, respectively, and net income attributable to BHE shareholders of $316 million and $73 million, respectively, as a result of including BHE GT&S from November 1, 2020. Additionally, BHE incurred $9 million of direct transaction costs associated with the GT&S Transaction that are included in operating expense on the Consolidated Statement of Operations for the year ended December 31, 2020.

Allocation of Purchase Price

BHE GT&S' assets acquired and liabilities assumed were measured at estimated fair value at closing. The majority of BHE GT&S' operations are subject to the rate-setting authority of the FERC and are accounted for pursuant to GAAP, including the authoritative guidance for regulated operations. The rate-setting and cost-recovery provisions provide for revenues derived from costs, including a return on investment of assets and liabilities included in rate base. As such, the fair value of BHE GT&S' assets acquired and liabilities assumed subject to these rate-setting provisions are assumed to approximate their carrying values and, therefore, no fair value adjustments have been reflected related to these amounts.

The fair value of BHE GT&S' assets acquired and liabilities assumed not subject to the rate-setting provisions discussed above was determined using an income and cost approach. The income approach is based on significant estimates and assumptions, including Level 3 inputs, which are judgmental in nature. The estimates and assumptions include the projected timing and amount of future cash flows, discount rates reflecting the risk inherent in the future cash flows and future market prices. Additionally, the fair value of long-term debt assumed was determined based on quoted market prices, which is considered a Level 2 fair value measurement.

The following table summarizes the fair values of the assets acquired and liabilities assumed as of the acquisition date (in millions):

	Fair Value
Current assets, including cash and cash equivalents of $104	$ 582
Property, plant and equipment	9,264
Goodwill	1,741
Regulatory assets	108
Deferred income taxes	284
Other long-term assets	1,424
Total assets	13,403
Current liabilities, including current portion of long-term debt of $1,200	1,616
Long-term debt, less current portion	4,415
Regulatory liabilities	650
Other long-term liabilities	292
Total liabilities	6,973
Noncontrolling interest	3,916
Net assets acquired	$ 2,514

During the year ended December 31, 2021, the Company made revisions to certain contracts and property, plant and equipment related to non-regulated operations, the equity method investment and associated deferred income tax amounts based upon the receipt of additional information about the facts and circumstances that existed as of the acquisition date. Provisional amounts were subject to further revision for up to 12 months following the acquisition date until the related valuations were completed.

Goodwill

The excess of the purchase price paid over the estimated fair values of the identifiable assets acquired and liabilities assumed totaled $1.7 billion and is reflected as goodwill in the BHE Pipeline Group reportable segment. The goodwill reflects the value paid primarily for the long-term opportunity to improve operating results through the efficient management of operating expenses and the deployment of capital. Goodwill is not amortized, but rather is reviewed annually for impairment or more frequently if indicators of impairment exist. For income tax purposes, the GT&S Acquisition is treated as a deemed asset acquisition resulting from tax elections being made, therefore all tax goodwill is deductible. Due to book and tax basis differences of certain items, book and tax goodwill will differ. The amount of tax goodwill is approximately $0.9 billion and will be amortized over 15 years.

Pro Forma Financial Information

The following unaudited pro forma financial information reflects the consolidated results of operations of BHE and the amortization of the purchase price adjustments assuming the acquisition had taken place on January 1, 2019, excluding non-recurring transaction costs incurred by BHE during 2020 (in millions):

	2020	2019
Operating revenue	$ 22,581	$ 21,979
Net income attributable to BHE shareholders	$ 6,800	$ 3,271

Other

In 2021, the Company completed various other acquisitions of residential real estate brokerage businesses 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	2021	2020
Regulated assets:			
Utility generation, transmission and distribution systems	5-80 years	$ 90,223	$ 86,730
Interstate natural gas pipeline assets	3-80 years	17,423	16,667
		107,646	103,397
Accumulated depreciation and amortization		(32,680)	(30,662)
Regulated assets, net		74,966	72,735
Nonregulated assets:			
Independent power plants	2-50 years	7,665	7,012
Cove Point LNG facility	40 years	3,364	3,339
Other assets	2-30 years	2,666	2,320
		13,695	12,671
Accumulated depreciation and amortization		(3,041)	(2,586)
Nonregulated assets, net		10,654	10,085
Net operating assets		85,620	82,820
Construction work-in-progress		4,196	3,308
Property, plant and equipment, net		$ 89,816	$ 86,128

Construction work-in-progress includes $3.8 billion and $3.2 billion as of December 31, 2021 and 2020, 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, 2021 (dollars in millions):

	Company Share	Facility In Service	Accumulated Depreciation and Amortization	Construction Work-in-Progress
PacifiCorp:				
Jim Bridger Nos. 1-4	67 %	$ 1,523	$ 812	$ 15
Hunter No. 1	94	489	221	8
Hunter No. 2	60	306	138	1
Wyodak	80	477	269	8
Colstrip Nos. 3 and 4	10	260	161	3
Hermiston	50	185	99	—
Craig Nos. 1 and 2	19	369	319	—
Hayden No. 1	25	77	47	—
Hayden No. 2	13	44	28	—
Transmission and distribution facilities	Various	879	269	118
Total PacifiCorp		4,609	2,363	153
MidAmerican Energy:				
Louisa No. 1	88 %	864	501	20
Quad Cities Nos. 1 and 2(1)	25	732	452	9
Walter Scott, Jr. No. 3	79	949	518	15
Walter Scott, Jr. No. 4(2)	60	225	134	8
George Neal No. 4	41	318	184	4
Ottumwa No. 1	52	674	264	11
George Neal No. 3	72	528	286	9
Transmission facilities	Various	263	100	4
Total MidAmerican Energy		4,553	2,439	80
NV Energy:				
Navajo	11 %	5	5	—
Valmy	50	394	309	1
On Line Transmission Line	25	160	31	1
Transmission facilities	Various	65	34	—
Total NV Energy		624	379	2
BHE Pipeline Group:				
Ellisburg Pool	39 %	31	11	1
Ellisburg Station	50	26	8	1
Harrison	50	53	18	—
Leidy	50	132	46	7
Oakford	50	200	68	2
Common Facilities	Various	276	166	—
Total BHE Pipeline Group		718	317	11
Total		$ 10,504	$ 5,498	$ 246

(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 $561 million and $127 million, respectively.

(6) Leases

The following table summarizes the Company's leases recorded on the Consolidated Balance Sheet as of December 31 (in millions):

	2021	2020
Right-of-use assets:		
Operating leases	$ 524	$ 517
Finance leases	448	501
Total right-of-use assets	$ 972	$ 1,018
Lease liabilities:		
Operating leases	$ 577	$ 569
Finance leases	463	514
Total lease liabilities	$ 1,040	$ 1,083

The following table summarizes the Company's lease costs for the years ended December 31 (in millions):

	2021	2020	2019
Variable	$ 611	$ 592	$ 623
Operating	161	151	170
Finance:			
Amortization	23	18	16
Interest	38	40	41
Short-term	15	20	7
Total lease costs	$ 848	$ 821	$ 857
Weighted-average remaining lease term (years):			
Operating leases	7.6	7.4	7.6
Finance leases	28.1	27.5	28.8
Weighted-average discount rate:			
Operating leases	4.3 %	4.5 %	5.2 %
Finance leases	8.6 %	8.5 %	8.6 %

The following table summarizes the Company's supplemental cash flow information relating to leases for the years ended December 31 (in millions):

	2021	2020	2019
Cash paid for amounts included in the measurement of lease liabilities:			
Operating cash flows from operating leases	$ (163)	$ (152)	$ (153)
Operating cash flows from finance leases	(38)	(40)	(42)
Financing cash flows from finance leases	(28)	(24)	(19)
Right-of-use assets obtained in exchange for lease liabilities:			
Operating leases	$ 119	$ 83	$ 82
Finance leases	2	19	14

The Company has the following remaining lease commitments as of December 31, 2021 (in millions):

	Operating	Finance	Total
2022	$ 157	$ 72	$ 229
2023	124	62	186
2024	93	62	155
2025	71	60	131
2026	55	60	115
Thereafter	186	607	793
Total undiscounted lease payments	686	923	1,609
Less - amounts representing interest	(109)	(460)	(569)
Lease liabilities	$ 577	$ 463	$ 1,040

(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	2021	2020
Asset retirement obligations	14 years	$ 742	$ 640
Deferred net power costs	1 year	531	139
Employee benefit plans(1)	15 years	472	722
Deferred income taxes(2)	Various	342	283
Asset disposition costs	Various	285	347
Demand side management	10 years	211	197
Unrealized loss on regulated derivative contracts	Various	157	31
Environmental costs	28 years	108	89
Deferred operating costs	9 years	103	124
Other	Various	1,012	868
Total regulatory assets		$ 3,963	$ 3,440
Reflected as:			
Current assets		$ 544	$ 283
Noncurrent assets		3,419	3,157
Total regulatory assets		$ 3,963	$ 3,440

(1) Includes amounts not yet recognized as a component of net periodic benefit cost that are expected to be included in regulated rates when recognized.

(2) 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.

The Company had regulatory assets not earning a return on investment of $1.8 billion and $1.6 billion as of December 31, 2021 and 2020, 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	2021	2020
Deferred income taxes[1]	Various	$ 3,185	$ 3,600
Cost of removal[2]	26 years	2,424	2,435
Asset retirement obligations	31 years	345	305
Levelized depreciation	29 years	259	281
Employee benefit plans[3]	Various	243	187
Other	Various	758	667
Total regulatory liabilities		$ 7,214	$ 7,475
Reflected as:			
Current liabilities		$ 254	$ 254
Noncurrent liabilities		6,960	7,221
Total regulatory liabilities		$ 7,214	$ 7,475

(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) 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.

(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):

	2021	2020
Investments:		
BYD Company Limited common stock	$ 7,693	$ 5,897
Rabbi trusts	492	440
Other	305	263
Total investments	8,490	6,600
Equity method investments:		
BHE Renewables tax equity investments	4,931	5,626
Iroquois Gas Transmission System, L.P.	735	580
Electric Transmission Texas, LLC	595	594
JAX LNG, LLC	92	75
Bridger Coal Company	45	74
Other	156	118
Total equity method investments	6,554	7,067
Restricted cash and cash equivalents and investments:		
Quad Cities Station nuclear decommissioning trust funds	768	676
Other restricted cash and cash equivalents	148	155
Total restricted cash and cash equivalents and investments	916	831
Total investments and restricted cash and cash equivalents and investments	$ 15,960	$ 14,498
Reflected as:		
Other current assets	$ 172	$ 178
Noncurrent assets	15,788	14,320
Total investments and restricted cash and cash equivalents and investments	$ 15,960	$ 14,498

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):

	2021	2020	2019
Unrealized gains (losses) recognized on marketable securities held at the reporting date	$ 1,819	$ 4,791	$ (290)
Net gains recognized on marketable securities sold during the period	4	6	2
Gains (losses) on marketable securities, net	$ 1,823	$ 4,797	$ (288)

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 has made contributions of $— million, $2,736 million and $1,619 million in 2021, 2020 and 2019, respectively, and has commitments as of December 31, 2021, subject to satisfaction of certain specified conditions, to provide equity contributions of $356 million in 2022 pursuant to these equity capital contribution agreements as the various projects achieve commercial operation. However, the Company expects to assign its rights and obligations under these equity capital contribution agreements, including any related funding commitments, to an entity affiliated through common ownership. 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 Iroquois, which owns and operates an interstate natural gas pipeline located in the states of New York and Connecticut; (ii) 50% of Electric Transmission Texas, LLC, which owns and operates electric transmission assets in the Electric Reliability Council of Texas footprint; (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 the 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.

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]
2021:								
Credit facilities[2]	$ 3,500	$ 1,200	$ 1,509	$ 650	$ 271	$ 851	$ 3,300	$ 11,281
Less:								
Short-term debt	—	—	—	(339)	(1)	(245)	(1,424)	(2,009)
Tax-exempt bond support and letters of credit	—	(218)	(370)	—	—	(1)	—	(589)
Net credit facilities	$ 3,500	$ 982	$ 1,139	$ 311	$ 270	$ 605	$ 1,876	$ 8,683
2020:								
Credit facilities[2]	$ 3,500	$ 1,200	$ 1,509	$ 650	$ 228	$ 923	$ 3,020	$ 11,030
Less:								
Short-term debt	—	(93)	—	(45)	(23)	(225)	(1,900)	(2,286)
Tax-exempt bond support and letters of credit	—	(218)	(370)	—	—	(2)	—	(590)
Net credit facilities	$ 3,500	$ 889	$ 1,139	$ 605	$ 205	$ 696	$ 1,120	$ 8,154

(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 drawn uncommitted credit facilities totaling $1 million and $23 million, respectively, at Northern Powergrid as of December 31, 2021 and 2020.

As of December 31, 2021, 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 2024 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 Eurodollar rate 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, 2021 and 2020, BHE did not have any commercial paper borrowings outstanding. 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, 2021 and 2020, BHE had $101 million and $105 million, respectively, of letters of credit outstanding. These letters of credit primarily support power purchase agreements and debt service requirements at certain subsidiaries of BHE Renewables, LLC expiring through April 2023 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 $1.2 billion unsecured credit facility expiring in June 2024 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 Eurodollar 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.

As of December 31, 2021, PacifiCorp did not have any commercial paper borrowings outstanding. As of December 31, 2020, PacifiCorp had $93 million of commercial paper outstanding with a weighted average interest rate of 0.16%. The credit facility requires 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, 2021 and 2020, PacifiCorp had $19 million and $11 million, respectively, of fully available letters of credit issued under committed arrangements in support of certain transactions required by third parties and 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.

MidAmerican Funding

As of December 31, 2021, MidAmerican Energy has $1.5 billion unsecured credit facility expiring in June 2024. In June 2021, MidAmerican Energy amended and restated its existing $900 million unsecured credit facility expiring June 2022. The amendment increased the commitment of the lenders to $1.5 billion, extended the expiration date to June 2024 and increased the available maturity extension options to an unlimited number, 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 Eurodollar rate 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, 2020, in addition to the $900 million unsecured credit facility discussed above, MidAmerican Energy had a $600 million unsecured credit facility expiring August 2021, which was terminated in June 2021. As of December 31, 2021 and 2020, 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.

NV Energy

Nevada Power has a $400 million secured credit facility expiring in June 2024 and Sierra Pacific has a $250 million secured credit facility expiring in June 2024 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 the Eurodollar rate 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, 2021 and 2020, the Nevada Utilities had borrowings of $339 million and $45 million outstanding under these credit facilities at a weighted average interest rate of 0.86% and 0.90%, respectively. 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.

Northern Powergrid

Northern Powergrid has a £200 million unsecured credit facility expiring in December 2024 with two one-year maturity extension options. 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.

AltaLink

AltaLink has a C$500 million secured revolving term credit facility expiring in December 2026 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 the Bankers' Acceptance rate, at AltaLink's option, based on AltaLink's credit ratings for its senior secured long-term debt securities. In addition, AltaLink has a C$75 million secured 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, United States base rate, or a spread above the Bankers' Acceptance rate, at AltaLink's option, based on AltaLink's credit ratings for its senior secured long-term debt securities.

As of December 31, 2021 and 2020, AltaLink had $108 million and $113 million outstanding under these facilities at a weighted average interest rate of 0.35% and 0.36%, respectively. The credit facilities require 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 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 to a maximum of C$10 million, has a variable interest rate based on the Canadian bank prime lending rate, United States base rate, or a spread above the Bankers' Acceptance rate, at AltaLink Investments, L.P.'s option, based on AltaLink Investments, L.P.'s credit ratings for its senior unsecured long-term debt securities.

AltaLink Investments, L.P. also has a C$200 million revolving term credit facility expiring in April 2022 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 to a maximum of C$10 million, has a variable interest rate based on the Canadian bank prime lending rate, United States base rate, or a spread above the Bankers' Acceptance rate, at AltaLink Investments, L.P.'s option, based on AltaLink Investments, L.P.'s credit ratings for its senior unsecured long-term debt securities. On an annual basis, with the consent of the lenders, AltaLink Investments, L.P. can request that the maturity date of the credit facility be extended for a further 365 days.

As of December 31, 2021 and 2020, AltaLink Investments, L.P. had $137 million and $112 million outstanding under this facility at a weighted average interest rate of 1.46% and 1.47%, 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.

HomeServices

HomeServices has an $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 the LIBOR 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, 2021 and 2020, HomeServices had $250 million and $100 million, respectively, outstanding under its credit facility with a weighted average interest rate of 0.95% and 1.15%, respectively.

Through its subsidiaries, HomeServices maintains mortgage lines of credit totaling $2.6 billion and $2.4 billion as of December 31, 2021 and 2020, respectively, used for mortgage banking activities that expire beginning in February 2022 through September 2022. The mortgage lines of credit have variable rates based on LIBOR 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, 2021 and 2020, HomeServices had $1.2 billion and $1.8 billion, respectively, outstanding under these mortgage lines of credit at a weighted average interest rate of 1.91% and 2.03%, respectively.

BHE Renewables Letters of Credit

As of December 31, 2021 and 2020, certain renewable projects collectively have letters of credit outstanding of $311 million and $305 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	2021	2020
2.375% Senior Notes, due 2021	$ —	$ —	$ 448
2.80% Senior Notes, due 2023	400	398	398
3.75% Senior Notes, due 2023	500	499	498
3.50% Senior Notes, due 2025	400	398	398
4.05% Senior Notes, due 2025	1,250	1,246	1,246
3.25% Senior Notes, due 2028	600	594	594
8.48% Senior Notes, due 2028	256	260	257
3.70% Senior Notes, due 2030	1,100	1,096	1,096
1.65% Senior Notes, due 2031	500	497	497
6.125% Senior Bonds, due 2036	1,670	1,661	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	740	740
4.50% Senior Notes, due 2045	750	738	738
3.80% Senior Notes, due 2048	750	738	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	1,488
Total BHE Senior Debt	$ 13,101	$ 13,003	$ 13,447
Reflected as:			
Current liabilities		$ —	$ 450
Noncurrent liabilities		13,003	12,997
Total BHE Senior Debt		$ 13,003	$ 13,447

Junior Subordinated Debentures

BHE junior subordinated debentures consists of the following as of December 31 (in millions):

	Par Value	2021	2020
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, 2021, 2020 and 2019.

(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, 2021, 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	2021	2020
PacifiCorp	$ 8,797	$ 8,730	$ 8,612
MidAmerican Funding	8,047	7,946	7,431
NV Energy	3,701	3,675	3,673
Northern Powergrid	3,321	3,287	3,259
BHE Pipeline Group	5,534	5,924	6,165
BHE Transmission	3,924	3,906	3,877
BHE Renewables	3,073	3,043	3,116
HomeServices	148	148	186
Total subsidiary debt	$ 36,545	$ 36,659	$ 36,319

	2021	2020
Reflected as:		
Current liabilities	$ 1,265	$ 1,389
Noncurrent liabilities	35,394	34,930
Total subsidiary debt	$ 36,659	$ 36,319

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	2021	2020
First mortgage bonds:			
2.95% to 8.53%, due through 2026	$ 1,379	$ 1,378	$ 2,245
2.70% to 7.70%, due 2027 to 2031	1,100	1,094	1,094
5.25% to 6.10%, due 2032 to 2036	850	845	845
5.75% to 6.35%, due 2037 to 2041	2,150	2,137	2,137
4.10%, due 2042	300	297	297
2.90% to 4.15%, due 2049 to 2052	2,800	2,761	1,776
Variable-rate series, tax-exempt bond obligations (2021-0.12% to 0.13%; 2020-0.14% to 0.16%):			
Due 2025	25	25	25
Due 2024 to 2025[1]	193	193	193
Total PacifiCorp	$ 8,797	$ 8,730	$ 8,612

(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.

The issuance of PacifiCorp's first mortgage bonds is limited by available property, earnings tests and other provisions of PacifiCorp's mortgage. Approximately $31 billion of PacifiCorp's eligible property (based on original cost) was subject to the lien of the mortgage as of December 31, 2021.

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	2021	2020
MidAmerican Funding:			
6.927% Senior Bonds, due 2029	$ 239	$ 225	$ 221
MidAmerican Energy:			
Tax-exempt bond obligations -			
Variable-rate tax-exempt bond obligation series: (weighted average interest rate - 2021-0.13%, 2020-0.14%), due 2023-2047	370	368	368
First Mortgage Bonds:			
3.70%, due 2023	250	250	249
3.50%, due 2024	500	501	501
3.10%, due 2027	375	373	373
3.65%, due 2029	850	860	862
4.80%, due 2043	350	346	346
4.40%, due 2044	400	395	395
4.25%, due 2046	450	446	445
3.95%, due 2047	475	470	470
3.65%, due 2048	700	689	689
4.25%, due 2049	900	874	873
3.15%, due 2050	600	592	592
2.70%, due 2052	500	492	—
Notes:			
6.75% Series, due 2031	400	397	397
5.75% Series, due 2035	300	298	298
5.80% Series, due 2036	350	348	348
Transmission upgrade obligation, 3.35% to 7.95%, due 2036 to 2041	38	22	4
Total MidAmerican Energy	7,808	7,721	7,210
Total MidAmerican Funding	$ 8,047	$ 7,946	$ 7,431

Pursuant to MidAmerican Energy's mortgage dated September 9, 2013, as amended by the First Supplemental Indenture dated as of September 19, 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. As of December 31, 2021, MidAmerican Energy's eligible property subject to the lien of the mortgage totaled approximately $22 billion based on original cost. 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, 2021 and 2020. MidAmerican Energy maintains revolving credit facility agreements to provide liquidity for holders of these issues and $180 million of the variable rate, tax-exempt bonds 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	2021	2020
Nevada Power:			
General and refunding mortgage securities:			
3.700% Series CC, due 2029	$ 500	$ 497	$ 496
2.400% Series DD, due 2030	425	422	422
6.650% Series N, due 2036	367	361	361
6.750% Series R, due 2037	349	347	347
5.375% Series X, due 2040	250	249	249
5.450% Series Y, due 2041	250	246	244
3.125% Series EE, due 2050	300	297	297
Tax-exempt refunding revenue bond obligations:			
Fixed-rate series:			
1.875% Pollution Control Bonds Series 2017A, due 2032(1)	40	39	39
1.650% Pollution Control Bonds Series 2017, due 2036(1)	40	39	39
1.650% Pollution Control Bonds Series 2017B, due 2039(1)	13	13	13
Total Nevada Power	2,534	2,510	2,507
Sierra Pacific:			
General and refunding mortgage securities:			
3.375% Series T, due 2023	250	249	249
2.600% Series U, due 2026	400	397	397
6.750% Series P, due 2037	252	254	256
Tax-exempt refunding revenue bond obligations:			
Fixed-rate series:			
1.850% Pollution Control Series 2016B, due 2029(2)	30	30	29
3.000% Gas and Water Series 2016B, due 2036(3)	60	60	61
0.625% Water Facilities Series 2016C, due 2036(2)	30	30	30
2.050% Water Facilities Series 2016D, due 2036(2)	25	25	25
2.050% Water Facilities Series 2016E, due 2036(2)	25	25	25
2.050% Water Facilities Series 2016F, due 2036(2)	75	75	74
1.850% Water Facilities Series 2016G, due 2036(2)	20	20	20
Total Sierra Pacific	1,167	1,165	1,166
Total NV Energy	$ 3,701	$ 3,675	$ 3,673

(1) Bonds were purchased by Nevada Power in May 2020 and re-offered at a fixed interest rate. Subject to mandatory purchase by Nevada Power in March 2023 at which date the interest rate may be adjusted.

(2) Subject to mandatory purchase by Sierra Pacific in April 2022 at which date the interest rate may be adjusted.

(3) Subject to mandatory purchase by Sierra Pacific in June 2022 at which date the interest rate may be adjusted.

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, 2021, approximately $9 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)]	2021	2020
4.133% European Investment Bank loans, due 2022	$ 204	$ 204	$ 206
7.25% Bonds, due 2022	271	269	277
2.50% Bonds, due 2025	203	202	203
2.073% European Investment Bank loan, due 2025	67	69	70
2.564% European Investment Bank loans, due 2027	338	337	340
7.25% Bonds, due 2028	251	254	257
4.375% Bonds, due 2032	203	200	202
5.125% Bonds, due 2035	271	268	270
5.125% Bonds, due 2035	203	201	203
2.750% Bonds, due 2049	203	200	202
2.250% Bonds, due 2059	406	398	402
1.875% Bonds, due 2062	406	398	403
Variable-rate loan, due 2026[(2)]	—	—	183
Variable-rate loan, due 2026[(3)]	—	—	41
Variable-rate loan, due 2026[(4)]	295	287	—
Total Northern Powergrid	$ 3,321	$ 3,287	$ 3,259

(1) The par values for these debt instruments are denominated in sterling.

(2) The Company had entered into an interest rate swap that fixed the interest rate on 89% of the outstanding debt. The variable interest rate as of December 31, 2020 was 2.03% (including 2.0% margin) and the fixed interest rate was 3.07% (including 2.0% margin), resulting in a blended rate of 2.96%.

(3) The variable interest rate as of December 31, 2020 was 2.02% (including 2.0% margin).

(4) 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, 2021 was 1.73% (including 1.55% margin) and the fixed interest rate was 2.45% (including 1.55% margin), resulting in a blended rate of 2.30%.

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	2021	2020
Eastern Energy Gas:			
Variable-rate Senior Notes, due 2021(1)	$ —	$ —	$ 500
2.875% Senior Notes, due 2023	250	250	249
3.55% Senior Notes, due 2023	400	399	399
2.50% Senior Notes, due 2024	600	597	596
3.60% Senior Notes, due 2024	339	338	448
3.32% Senior Notes, due 2026 (€250)(2)	284	283	304
3.00% Senior Notes, due 2029	174	173	594
3.80% Senior Notes, due 2031	150	150	150
4.80% Senior Notes, due 2043	54	53	395
4.60% Senior Notes, due 2044	56	56	493
3.90% Senior Notes, due 2049	27	26	297
EGTS:			
3.60% Senior Notes, due 2024	111	110	—
3.00% Senior Notes, due 2029	426	422	—
4.80% Senior Notes, due 2043	346	341	—
4.60% Senior Notes, due 2044	444	437	—
3.90% Senior Notes, due 2049	273	271	—
Total Eastern Energy Gas	3,934	3,906	4,425
Fair value adjustments	—	430	493
Total Eastern Energy Gas, net of fair value adjustments	3,934	4,336	4,918
Northern Natural Gas:			
4.25% Senior Notes, due 2021	—	—	200
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	650
3.40% Senior Bonds, due 2051	550	540	—
Total Northern Natural Gas	1,600	1,588	1,247
Total BHE Pipeline Group	$ 5,534	$ 5,924	$ 6,165

(1) The senior notes had variable interest rates based on LIBOR plus an applicable margin. Eastern Energy Gas entered into an interest rate swap that fixed the interest rate on 100% of the notes. The fixed interest rate as of December 31, 2020 was 3.46% including a 0.60% margin.

(2) 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, 2021 and 2020 that averaged 3.32%.

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)	2021	2020
AltaLink Investments, L.P.:			
Series 15-1 Senior Bonds, 2.244%, due 2022	$ 158	$ 158	$ 157
Total AltaLink Investments, L.P.	158	158	157
AltaLink, L.P.:			
Series 2012-2 Notes, 2.978%, due 2022	218	218	216
Series 2013-4 Notes, 3.668%, due 2023	396	395	392
Series 2014-1 Notes, 3.399%, due 2024	277	277	275
Series 2016-1 Notes, 2.747%, due 2026	277	276	274
Series 2020-1 Notes, 1.509%, due 2030	178	177	175
Series 2006-1 Notes, 5.249%, due 2036	119	118	118
Series 2010-1 Notes, 5.381%, due 2040	99	99	98
Series 2010-2 Notes, 4.872%, due 2040	119	118	117
Series 2011-1 Notes, 4.462%, due 2041	218	217	215
Series 2012-1 Notes, 3.990%, due 2042	415	410	407
Series 2013-3 Notes, 4.922%, due 2043	277	276	274
Series 2014-3 Notes, 4.054%, due 2044	233	232	230
Series 2015-1 Notes, 4.090%, due 2045	277	275	273
Series 2016-2 Notes, 3.717%, due 2046	356	354	351
Series 2013-1 Notes, 4.446%, due 2053	198	197	196
Series 2014-2 Notes, 4.274%, due 2064	103	103	102
Total AltaLink, L.P.	3,760	3,742	3,713
Other:			
Construction Loan, 5.620%, due 2024	6	6	7
Total BHE Transmission	$ 3,924	$ 3,906	$ 3,877

(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	2021	2020
Fixed-rate[1]:			
Bishop Hill Holdings Senior Notes, 5.125%, due 2032	$ 62	$ 62	$ 69
Solar Star Funding Senior Notes, 3.950%, due 2035	258	256	269
Solar Star Funding Senior Notes, 5.375%, due 2035	826	819	853
Grande Prairie Wind Senior Notes, 3.860%, due 2037	299	297	327
Topaz Solar Farms Senior Notes, 5.750%, due 2039	606	600	631
Topaz Solar Farms Senior Notes, 4.875%, due 2039	172	170	180
Alamo 6 Senior Notes, 4.170%, due 2042	199	197	205
Other	5	5	8
Variable-rate[1]:			
TX Jumbo Road Term Loan, due 2025[2]	119	117	138
Marshall Wind Term Loan, due 2026[2]	64	63	69
Flat Top Wind I Term Loan, due 2028[2]	113	113	—
Pinyon Pines I and II Term Loans, due 2034[2]	350	344	367
Total BHE Renewables	$ 3,073	$ 3,043	$ 3,116

(1) Amortizes quarterly or semiannually.

(2) The term loans have variable interest rates based on LIBOR or Secured Overnight Financing Rate 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, 2021 and 2020 ranged from 3.21% to 3.88%. The variable interest rate on the Flat Top Wind I outstanding debt was 6.34% as of December 31, 2021.

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	2021	2020
Variable-rate:			
Variable-rate term loan (2021 - 0.950%, 2020 - 1.147%), due 2026[1]	$ 148	$ 148	$ 186

(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, 2022 and thereafter, excluding fair value adjustments and unamortized premiums, discounts and debt issuance costs, are as follows (in millions):

	2022	2023	2024	2025	2026	2027 and Thereafter	Total
BHE senior notes	$ —	$ 900	$ —	$ 1,650	$ —	$ 10,551	$ 13,101
BHE junior subordinated debentures	—	—	—	—	—	100	100
PacifiCorp	155	449	592	301	100	7,200	8,797
MidAmerican Funding	—	316	537	15	2	7,177	8,047
NV Energy	—	250	—	—	400	3,051	3,701
Northern Powergrid	526	56	56	318	84	2,281	3,321
BHE Pipeline Group	—	650	1,050	—	284	3,550	5,534
BHE Transmission	377	397	282	—	277	2,591	3,924
BHE Renewables	199	200	210	241	218	2,005	3,073
HomeServices	8	7	9	15	109	—	148
Totals	$ 1,265	$ 3,225	$ 2,736	$ 2,540	$ 1,474	$ 38,506	$ 49,746

(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 United States federal and Iowa state income tax returns and the majority of the Company's United States federal income tax is remitted to or received from Berkshire Hathaway. As of December 31, 2021, the Company had a current income tax receivable from Berkshire Hathaway for federal income tax of $324 million and a long-term income tax receivable from Berkshire Hathaway, reflected as a component of BHE's shareholders' equity, of $744 million for Iowa state income tax. As of December 31, 2020, the Company had a current income tax receivable from Berkshire Hathaway for federal income tax of $13 million and a long-term income tax receivable from Berkshire Hathaway, reflected as a component of BHE's shareholders' equity, of $658 million for Iowa state income tax. Additionally, for the years ended December 31, 2021 and 2020 the Company generated $100 million and $138 million, respectively, of Iowa state net operating losses which were carried forward and increased the long-term income tax receivable from Berkshire Hathaway.

The BHE GT&S acquisition on November 1, 2020 was treated as a deemed asset acquisition for federal and state income tax purposes due to Berkshire Hathaway and DEI making tax elections under Internal Revenue Code ("IRC") §338(h)(10) for all C-corporations acquired, the intent on making or having in place IRC §754 elections for any partnership interests purchased, and due to all single member LLCs acquired being treated as disregarded entities for income tax purposes. All deferred taxes at BHE GT&S were reset to reflect book and tax basis differences as of November 1, 2020. The primary deferred tax items recorded by the Company include long-term debt, pension and other postretirement liabilities, and intangible assets. Since the BHE GT&S acquisition is deemed an asset acquisition for federal and state income tax purposes, all of the approximately $0.9 billion of tax goodwill is amortizable over 15 years. At the acquisition date there is no deferred tax liability recorded for the difference between book goodwill of approximately $1.7 billion versus the tax goodwill of approximately $0.9 billion, due to the inability to record a deferred tax liability when book goodwill exceeds tax goodwill.

Income tax (benefit) expense consists of the following for the years ended December 31 (in millions):

	2021	2020	2019
Current:			
Federal	$ (1,701)	$ (1,537)	$ (956)
State	(177)	(121)	(13)
Foreign	100	86	81
	(1,778)	(1,572)	(888)
Deferred:			
Federal	1,037	1,438	431
State	(476)	424	(127)
Foreign	89	21	(8)
	650	1,883	296
Investment tax credits	(4)	(3)	(6)
Total	$ (1,132)	$ 308	$ (598)

A reconciliation of the federal statutory income tax rate to the effective income tax rate applicable to income before income tax (benefit) expense is as follows for the years ended December 31:

	2021	2020	2019
Federal statutory income tax rate	21 %	21 %	21 %
Income tax credits	(27)	(16)	(32)
Effects of ratemaking	(4)	(3)	(6)
State income tax, net of federal income tax benefit	(10)	3	(5)
Non-controlling interest	(2)	—	—
Income tax effect of foreign income	1	—	(2)
Other, net	—	(1)	(1)
Effective income tax rate	(21)%	4 %	(25)%

Income tax credits relate primarily to production tax credits ("PTC") from wind-powered generating facilities owned by MidAmerican Energy, PacifiCorp and BHE Renewables. 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, 2021, 2020 and 2019 totaled $1.4 billion, $1.2 billion, and $0.8 billion, respectively.

Income tax effect on foreign income includes, among other items, deferred income tax charges of $105 million and $35 million in 2021 and 2020, respectively, related to the United Kingdom's corporate income tax rate. The United Kingdom's rate is scheduled to increase from 19% to 25%, effective April 1, 2023, through legislation enacted in June 2021. The United Kingdom's rate was scheduled to decrease from 19% to 17% effective April 1, 2020; however, the rate was maintained at 19% through amended legislation enacted in July 2020.

The net deferred income tax liability consists of the following as of December 31 (in millions):

	2021	2020
Deferred income tax assets:		
Regulatory liabilities	$ 1,349	$ 1,420
Federal, state and foreign carryforwards	820	677
AROs	304	304
Other	686	777
Total deferred income tax assets	3,159	3,178
Valuation allowances	(164)	(204)
Total deferred income tax assets, net	2,995	2,974
Deferred income tax liabilities:		
Property-related items	(11,814)	(10,816)
Investments	(2,877)	(2,821)
Regulatory assets	(764)	(785)
Other	(478)	(327)
Total deferred income tax liabilities	(15,933)	(14,749)
Net deferred income tax liability	$ (12,938)	$ (11,775)

The following table provides the Company's net operating loss and tax credit carryforwards and expiration dates as of December 31, 2021 (in millions):

	Federal	State	Foreign	Total
Net operating loss carryforwards[(1)]	$ 297	$ 9,013	$ 900	$ 10,210
Deferred income taxes on net operating loss carryforwards	63	506	207	776
Expiration dates	2022 - indefinite	2022 - indefinite	2028 - 2041	
Tax credits	$ 15	$ 29	$ —	$ 44
Expiration dates	2023 - 2034	2022 - indefinite		

(1) The federal net operating loss carryforwards relate principally to net operating loss carryforwards of subsidiaries that are tax residents in both the United States and the United Kingdom. The federal net operating loss carryforwards were generated prior to Berkshire Hathaway Inc.'s ownership and will begin to expire in 2022.

The United States 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 through December 31, 2011, for California, Michigan, Minnesota, Montana, Nebraska, Oregon, Utah and Wisconsin, and through December 31, 2017, except for the impact of any federal audit adjustments, for Connecticut, District of Columbia, Idaho, Illinois, Iowa, Kansas and New York. 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):

	2021	2020
Beginning balance	$ 153	$ 145
Additions based on tax positions related to the current year	24	19
Additions for tax positions of prior years	13	6
Reductions based on tax positions related to the current year	(19)	(14)
Reductions for tax positions of prior years	(83)	(1)
Statute of limitations	—	(4)
Settlements	(1)	1
Interest and penalties	10	1
Ending balance	$ 97	$ 153

As of December 31, 2021 and 2020, the Company had unrecognized tax benefits totaling $100 million and $141 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.

On November 1, 2020, BHE completed its acquisition of substantially all of the natural gas transmission and storage business of DEI and Dominion Questar, exclusive of the Questar Pipeline Group (the "GT&S Transaction"). Defined benefit pension and postretirement benefits provided to the employees of BHE GT&S, which were part of the GT&S Transaction completed on November 1, 2020, are administered in the respective plans sponsored by MidAmerican Energy. Initial pension and postretirement plan liabilities of $81 million and $37 million, respectively, resulted from the GT&S Transaction.

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 (credit) for the plans included the following components for the years ended December 31 (in millions):

	Pension			Other Postretirement		
	2021	2020	2019	2021	2020	2019
Service cost	$ 30	$ 17	$ 16	$ 12	$ 7	$ 8
Interest cost	78	93	111	19	21	27
Expected return on plan assets	(134)	(140)	(154)	(22)	(34)	(40)
Settlement	3	—	—	—	—	—
Net amortization	25	32	31	(3)	(4)	(6)
Net periodic benefit cost (credit)	$ 2	$ 2	$ 4	$ 6	$ (10)	$ (11)

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	
	2021	2020	2021	2020
Plan assets at fair value, beginning of year	$ 2,824	$ 2,656	$ 744	$ 742
Employer contributions	13	13	14	3
Participant contributions	—	—	9	8
Actual return on plan assets	234	373	53	40
Settlement	(134)	—	—	—
Benefits paid	(142)	(218)	(51)	(49)
Plan assets at fair value, end of year	$ 2,795	$ 2,824	$ 769	$ 744

The following table is a reconciliation of the benefit obligations for the years ended December 31 (in millions):

	Pension		Other Postretirement	
	2021	2020	2021	2020
Benefit obligation, beginning of year	$ 3,077	$ 2,878	$ 758	$ 673
Service cost	30	17	12	7
Interest cost	78	93	19	21
Participant contributions	—	—	9	8
Actuarial (gain) loss	(132)	226	(35)	61
Amendment	—	—	2	—
Settlement	(134)	—	—	—
Acquisition	—	81	—	37
Benefits paid	(142)	(218)	(51)	(49)
Benefit obligation, end of year	$ 2,777	$ 3,077	$ 714	$ 758
Accumulated benefit obligation, end of year	$ 2,713	$ 2,999		

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	
	2021	2020	2021	2020
Plan assets at fair value, end of year	$ 2,795	$ 2,824	$ 769	$ 744
Benefit obligation, end of year	2,777	3,077	714	758
Funded status	$ 18	$ (253)	$ 55	$ (14)
Amounts recognized on the Consolidated Balance Sheets:				
Other assets	$ 204	$ 43	$ 60	$ 20
Other current liabilities	(13)	(13)	—	—
Other long-term liabilities	(173)	(283)	(5)	(34)
Amounts recognized	$ 18	$ (253)	$ 55	$ (14)

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 $343 million and $303 million as of December 31, 2021 and 2020, 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	
	2021	2020	2021	2020
Fair value of plan assets	$ —	$ 1,782	$ 137	$ 417
Projected benefit obligation	$ 186	$ 2,069	$ 142	$ 451
Fair value of plan assets	$ —	$ 1,064		
Accumulated benefit obligation	$ 185	$ 1,341		

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	
	2021	2020	2021	2020
Net loss (gain)	$ 343	$ 612	$ (34)	$ 34
Prior service credit	(1)	(1)	(1)	(9)
Regulatory deferrals	11	2	2	3
Total	$ 353	$ 613	$ (33)	$ 28

A reconciliation of the amounts not yet recognized as components of net periodic benefit cost for the years ended December 31, 2021 and 2020 is as follows (in millions):

	Regulatory Asset	Regulatory Liability	Accumulated Other Comprehensive Loss	Total
Pension				
Balance, December 31, 2019	$ 661	$ (33)	$ 24	$ 652
Net (gain) loss arising during the year	(30)	13	10	(7)
Net amortization	(31)	—	(1)	(32)
Total	(61)	13	9	(39)
Balance, December 31, 2020	600	(20)	33	613
Net gain arising during the year	(177)	(44)	(10)	(231)
Settlement	(9)	5	—	(4)
Net amortization	(24)	—	(1)	(25)
Total	(210)	(39)	(11)	(260)
Balance, December 31, 2021	$ 390	$ (59)	$ 22	$ 353

	Regulatory Asset	Regulatory Liability	Accumulated Other Comprehensive Loss	Total
Other Postretirement				
Balance, December 31, 2019	$ 4	$ (32)	$ (3)	$ (31)
Net loss arising during the year	36	12	7	55
Net amortization	7	(3)	—	4
Total	43	9	7	59
Balance, December 31, 2020	47	(23)	4	28
Net gain arising during the year	(40)	(22)	(3)	(65)
Net prior service cost arising during the year	1	—	—	1
Net amortization	3	—	—	3
Total	(36)	(22)	(3)	(61)
Balance, December 31, 2021	$ 11	$ (45)	$ 1	$ (33)

Plan Assumptions

Weighted-average assumptions used to determine benefit obligations and net periodic benefit cost were as follows:

	Pension			Other Postretirement		
	2021	2020	2019	2021	2020	2019
Benefit obligations as of December 31:						
Discount rate	2.98 %	2.60 %	3.32 %	2.95 %	2.59 %	3.24 %
Rate of compensation increase	2.75 %	2.75 %	2.75 %	N/A	N/A	N/A
Interest crediting rates for cash balance plan						
2019	N/A	N/A	3.22 %	N/A	N/A	N/A
2020	N/A	2.44 %	2.94 %	N/A	N/A	N/A
2021	2.45 %	2.25 %	2.94 %	N/A	N/A	N/A
2022	2.56 %	2.25 %	3.02 %	N/A	N/A	N/A
2023	2.56 %	2.65 %	3.02 %	N/A	N/A	N/A
2024 and beyond	2.83 %	2.65 %	3.02 %	N/A	N/A	N/A
Net periodic benefit cost for the years ended December 31:						
Discount rate	2.60 %	3.32 %	4.25 %	2.59 %	3.24 %	4.21 %
Expected return on plan assets	5.39 %	5.94 %	6.48 %	3.35 %	5.42 %	6.39 %
Rate of compensation increase	2.75 %	2.75 %	2.75 %	N/A	N/A	N/A
Interest crediting rate for cash balance plan	2.45 %	2.44 %	3.22 %	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.

	2021	2020
Assumed healthcare cost trend rates as of December 31:		
Healthcare cost trend rate assumed for next year	6.00 %	6.30 %
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	2025	2025

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 2022. 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 2022 through 2026 and for the five years thereafter are summarized below (in millions):

	Projected Benefit Payments	
	Pension	Other Postretirement
2022	$ 210	$ 54
2023	203	54
2024	195	54
2025	193	53
2026	193	51
2027-2031	837	229

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 advisors to manage 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, 2021:

	Pension	Other Postretirement
	%	%
PacifiCorp:		
Debt securities(1)	55-85	70-80
Equity securities(1)	25-35	20-30
Limited partnership interests	0-10	0-1
MidAmerican Energy:		
Debt securities(1)	60-80	25-35
Equity securities(1)	20-40	65-75
Other	0-15	0-5
NV Energy:		
Debt securities(1)	85-100	67-88
Equity securities(1)	0-15	12-33

(1) For purposes of target allocation percentages and consistent with the plans' investment policy, investment funds are allocated based on the underlying investments in debt and equity securities.

Fair Value Measurements

The following table presents the fair value of plan assets, by major category, for the Company's defined benefit pension plans (in millions):

	Input Levels for Fair Value Measurements[1]		
	Level 1	Level 2	Total
As of December 31, 2021:			
Cash equivalents	$ —	$ 64	$ 64
Debt securities:			
United States government obligations	142	—	142
Corporate obligations	—	912	912
Municipal obligations	—	66	66
Agency, asset and mortgage-backed obligations	—	93	93
Equity securities:			
United States companies	135	—	135
Total assets in the fair value hierarchy	$ 277	$ 1,135	1,412
Investment funds[2] measured at net asset value			1,349
Limited partnership interests[3] measured at net asset value			34
Total assets measured at fair value			$ 2,795
As of December 31, 2020:			
Cash equivalents	$ —	$ 79	$ 79
Debt securities:			
United States government obligations	52	—	52
Corporate obligations	—	748	748
Municipal obligations	—	69	69
Equity securities:			
United States companies	224	—	224
Total assets in the fair value hierarchy	$ 276	$ 896	1,172
Investment funds[2] measured at net asset value			1,521
Limited partnership interests[3] measured at net asset value			88
Real estate funds measured at net asset value			43
Total assets measured at fair value			$ 2,824

(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 54% and 46%, respectively, for 2021 and 69% and 31%, respectively, for 2020. Additionally, these funds are invested in United States and international securities of approximately 89% and 11%, respectively, for 2021 and 79% and 21%, respectively, for 2020.

(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, 2021:			
Cash equivalents	$ 12	$ 4	$ 16
Debt securities:			
United States government obligations	27	—	27
Corporate obligations	—	85	85
Municipal obligations	—	43	43
Agency, asset and mortgage-backed obligations	—	38	38
Equity securities:			
United States companies	4	—	4
Investment funds(2)	394	—	394
Total assets in the fair value hierarchy	$ 437	$ 170	607
Investment funds(2) measured at net asset value			161
Limited partnership interests(3) measured at net asset value			1
Total assets measured at fair value			$ 769
As of December 31, 2020:			
Cash equivalents	$ 20	$ 2	$ 22
Debt securities:			
United States government obligations	15	—	15
Corporate obligations	—	102	102
Municipal obligations	—	82	82
Agency, asset and mortgage-backed obligations	—	47	47
Equity securities:			
United States companies	6	—	6
Investment funds(2)	299	—	299
Total assets in the fair value hierarchy	$ 340	$ 233	573
Investment funds(2) measured at net asset value			167
Limited partnership interests(3) measured at net asset value			4
Total assets measured at fair value			$ 744

(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 2021 and 40% and 60%, respectively, for 2020. Additionally, these funds are invested in United States and international securities of approximately 88% and 12%, respectively, for 2021 and 79% and 21%, respectively, for 2020.

(3) Limited partnership interests include several funds that invest primarily in real estate, buyout, growth equity and venture capital.

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 for the UK Plan included the following components for the years ended December 31 (in millions):

	2021	2020	2019
Service cost	$ 16	$ 16	$ 16
Interest cost	31	40	49
Expected return on plan assets	(111)	(101)	(100)
Settlement	10	17	26
Net amortization	55	43	46
Net periodic benefit cost	$ 1	$ 15	$ 37

Funded Status

The following table is a reconciliation of the fair value of plan assets for the years ended December 31 (in millions):

	2021	2020
Plan assets at fair value, beginning of year	$ 2,334	$ 2,151
Employer contributions	28	56
Participant contributions	1	1
Actual return on plan assets	148	181
Settlement	(51)	(63)
Benefits paid	(72)	(67)
Foreign currency exchange rate changes	(25)	75
Plan assets at fair value, end of year	$ 2,363	$ 2,334

The following table is a reconciliation of the benefit obligation for the years ended December 31 (in millions):

	2021	2020
Benefit obligation, beginning of year	$ 2,205	$ 2,019
Service cost	16	16
Interest cost	31	40
Participant contributions	1	1
Actuarial (gain) loss	(105)	188
Settlement	(51)	(63)
Benefits paid	(72)	(67)
Foreign currency exchange rate changes	(22)	71
Benefit obligation, end of year	$ 2,003	$ 2,205
Accumulated benefit obligation, end of year	$ 1,778	$ 1,963

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):

	2021	2020
Plan assets at fair value, end of year	$ 2,363	$ 2,334
Benefit obligation, end of year	2,003	2,205
Funded status	$ 360	$ 129
Amounts recognized on the Consolidated Balance Sheets:		
Other assets	$ 360	$ 129

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):

	2021	2020
Net loss	$ 400	$ 612
Prior service cost	5	6
Total	$ 405	$ 618

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):

	2021	2020
Balance, beginning of year	$ 618	$ 549
Net loss arising during the year	(143)	108
Settlement	(10)	(17)
Net amortization	(55)	(43)
Foreign currency exchange rate changes	(5)	21
Total	(213)	69
Balance, end of year	$ 405	$ 618

Plan Assumptions

Assumptions used to determine benefit obligations and net periodic benefit cost were as follows:

	2021	2020	2019
Benefit obligations as of December 31:			
Discount rate	1.95 %	1.40 %	2.10 %
Rate of compensation increase	3.45 %	3.05 %	3.30 %
Rate of future price inflation	2.95 %	2.55 %	2.80 %
Net periodic benefit cost for the years ended December 31:			
Discount rate	1.40 %	2.10 %	2.90 %
Expected return on plan assets	4.85 %	5.00 %	5.10 %
Rate of compensation increase	3.05 %	3.30 %	3.55 %
Rate of future price inflation	2.55 %	2.80 %	3.05 %

Contributions and Benefit Payments

Employer contributions to the UK Plan are expected to be £12 million during 2022. The expected benefit payments to participants in the UK Plan for 2022 through 2026 and for the five years thereafter, excluding lump sum settlement elections and using the foreign currency exchange rate as of December 31, 2021, are summarized below (in millions):

2022	$	73
2023		75
2024		77
2025		79
2026		81
2027-2031		436

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, 2021:

	%
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, 2021:				
Cash equivalents	$ 5	$ 27	$ —	$ 32
Debt securities:				
United Kingdom government obligations	1,308	—	—	1,308
Equity securities:				
Investment funds[2]	—	646	—	646
Real estate funds	—	—	269	269
Total	$ 1,313	$ 673	$ 269	2,255
Investment funds[2] measured at net asset value				108
Total assets measured at fair value				$ 2,363
As of December 31, 2020:				
Cash equivalents	$ 5	$ 49	$ —	$ 54
Debt securities:				
United Kingdom government obligations	1,102	—	—	1,102
Equity securities:				
Investment funds[2]	—	833	—	833
Real estate funds	—	—	237	237
Total	$ 1,107	$ 882	$ 237	2,226
Investment funds[2] measured at net asset value				108
Total assets measured at fair value				$ 2,334

(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 23% and 77%, respectively, for 2021 and 40% and 60%, respectively, for 2020.

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		
	2021	2020	2019
Beginning balance	$ 237	$ 243	$ 239
Actual return on plan assets still held at period end	35	(13)	(5)
Foreign currency exchange rate changes	(3)	7	9
Ending balance	$ 269	$ 237	$ 243

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 $137 million, $127 million and $115 million for the years ended December 31, 2021, 2020 and 2019, 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 $2.4 billion as of December 31, 2021 and 2020.

The following table presents the Company's ARO liabilities by asset type as of December 31 (in millions):

	2021	2020
Fossil fuel facilities	$ 466	$ 529
Quad Cities Station	427	376
Wind generating facilities	299	273
Solar generating facilities	25	24
Offshore pipeline facilities	14	16
Other	109	123
Total asset retirement obligations	$ 1,340	$ 1,341
Quad Cities Station nuclear decommissioning trust funds	$ 768	$ 676

The following table reconciles the beginning and ending balances of the Company's ARO liabilities for the years ended December 31 (in millions):

	2021	2020
Beginning balance	$ 1,341	$ 1,272
Change in estimated costs	81	46
Acquisitions	—	122
Additions	15	51
Retirements	(144)	(201)
Accretion	47	51
Ending balance	$ 1,340	$ 1,341
Reflected as:		
Other current liabilities	$ 130	$ 184
Other long-term liabilities	1,210	1,157
Total ARO liability	$ 1,340	$ 1,341

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, 2021:					
Assets:					
Commodity derivatives	$ 5	$ 271	$ 73	$ (47)	$ 302
Foreign currency exchange rate derivatives	—	3	—	—	3
Interest rate derivatives	1	3	20	—	24
Mortgage loans held for sale	—	1,263	—	—	1,263
Money market mutual funds	554	—	—	—	554
Debt securities:					
United States government obligations	232	—	—	—	232
International government obligations	—	2	—	—	2
Corporate obligations	—	90	—	—	90
Municipal obligations	—	3	—	—	3
Agency, asset and mortgage-backed obligations	—	2	—	—	2
Equity securities:					
United States companies	428	—	—	—	428
International companies	7,703	—	—	—	7,703
Investment funds	237	—	—	—	237
	$ 9,160	$ 1,637	$ 93	$ (47)	$ 10,843
Liabilities:					
Commodity derivatives	$ (2)	$ (113)	$ (224)	$ 73	$ (266)
Foreign currency exchange rate derivatives	—	(3)	—	—	(3)
Interest rate derivatives	—	(7)	(1)	—	(8)
	$ (2)	$ (123)	$ (225)	$ 73	$ (277)

As of December 31, 2020:

Assets:					
Commodity derivatives	$ 1	$ 73	$ 135	$ (21)	$ 188
Foreign currency exchange rate derivatives	—	20	—	—	20
Interest rate derivatives	—	—	62	—	62
Mortgage loans held for sale	—	2,001	—	—	2,001
Money market mutual funds	873	—	—	—	873
Debt securities:					
United States government obligations	200	—	—	—	200
International government obligations	—	5	—	—	5
Corporate obligations	—	73	—	—	73
Municipal obligations	—	2	—	—	2
Agency, asset and mortgage-backed obligations	—	6	—	—	6
Equity securities:					
United States companies	381	—	—	—	381
International companies	5,906	—	—	—	5,906
Investment funds	201	—	—	—	201
	$ 7,562	$ 2,180	$ 197	$ (21)	$ 9,918
Liabilities:					
Commodity derivatives	$ (1)	$ (90)	$ (19)	$ 56	$ (54)
Foreign currency exchange rate derivatives	—	(2)	—	—	(2)
Interest rate derivatives	(5)	(60)	—	—	(65)
	$ (6)	$ (152)	$ (19)	$ 56	$ (121)

(1) Represents netting under master netting arrangements and a net cash collateral receivable of $26 million and $35 million as of December 31, 2021 and 2020, 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):

	Commodity Derivatives			Interest Rate Derivatives		
	2021	2020	2019	2021	2020	2019
Beginning balance	$ 116	$ 97	$ 99	$ 62	$ 14	$ 10
Changes included in earnings[1]	(43)	(10)	10	(43)	48	4
Changes in fair value recognized in OCI	(13)	—	(1)	—	—	—
Changes in fair value recognized in net regulatory assets	(118)	(17)	(26)	—	—	—
Purchases	(76)	5	6	—	—	—
Settlements	(34)	41	9	—	—	—
Transfers to Level 2	17	—	—	—	—	—
Ending balance	$ (151)	$ 116	$ 97	$ 19	$ 62	$ 14

(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):

	2021		2020	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 49,762	$ 57,189	$ 49,866	$ 60,633

(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, 2021 are as follows (in millions):

	2022	2023	2024	2025	2026	2027 and Thereafter	Total
Contract type:							
Fuel, capacity and transmission contract commitments	$ 2,475	$ 1,635	$ 1,422	$ 1,164	$ 1,054	$ 11,964	$ 19,714
Construction commitments	1,329	831	776	87	4	—	3,027
Easements	82	84	80	82	83	2,870	3,281
Maintenance, service and other contracts	474	364	300	249	240	1,543	3,170
	$ 4,360	$ 2,914	$ 2,578	$ 1,582	$ 1,381	$ 16,377	$ 29,192

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, 2021, 2020 and 2019, $76 million, $90 million and $123 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-powered generating facilities 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 and certain other generating plant projects and costs associated with two additional solar photovoltaic facility projects. The first project is a 250-MW solar photovoltaic facility with an additional 200 MWs of co-located battery storage that will be developed in Humboldt County, Nevada. Commercial operation is expected by the end of 2023. The second project is a 350-MW solar photovoltaic facility with an additional 280 MWs of co-located battery storage that will be developed in Humboldt County, Nevada. Commercial operation is expected by the end of 2024. Both facilities will be jointly owned and operated by Nevada Power and Sierra Pacific.
- 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-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.

Legal Matters

The Company is party to a variety of legal actions arising out of the normal course of business. Plaintiffs occasionally seek punitive or exemplary damages. The Company does not believe that such normal and routine litigation will have a material impact on its consolidated financial results.

California and Oregon 2020 Wildfires

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 damage, personal injuries and loss of life and widespread power outages in Oregon and Northern California (the "2020 Wildfires"). 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. Fire suppression costs estimated by various agencies total approximately $150 million. Investigations into the cause and origin of each wildfire are complex and ongoing and being conducted by various entities, including the United States Forest Service, the California Public Utilities Commission, the Oregon Department of Forestry, the Oregon Department of Justice, PacifiCorp and various experts engaged by PacifiCorp.

Several lawsuits have been filed in Oregon and California, including a putative class action complaint in Oregon, on behalf of citizens and businesses who suffered damages from fires allegedly caused by PacifiCorp. Additionally, multiple insurance carriers have filed subrogation complaints in Oregon and California with allegations similar to those made in the aforementioned lawsuits. The final determinations of liability, however, will only be made following comprehensive investigations and litigation processes.

In California, under inverse condemnation, courts have held that investor-owned utilities can be liable for real and personal property damages 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 nevertheless be found liable for all damages proximately caused by negligence, including property and natural resource damage; fire suppression costs; personal injury and loss of life damages; and interest.

PacifiCorp has accrued $136 million as its best estimate of the potential losses net of expected insurance recoveries associated with the 2020 Wildfires that are considered probable of being incurred. These accruals include estimated losses for fire suppression costs, property damage, personal injury damages and loss of life damages. It is reasonably possible that PacifiCorp will incur additional losses beyond the amounts accrued; however, PacifiCorp is currently unable to estimate the range of possible additional losses that could be incurred due to the number of properties and parties involved and the lack of specific claims for all potential claimants. To the extent losses beyond the amounts accrued are incurred, additional insurance coverage is expected to be available to cover at least a portion of the losses.

Environmental Laws and Regulations

The Company is subject to federal, state, local and foreign laws and regulations regarding climate change, renewable portfolio standards, air and water quality, emissions performance standards, coal combustion byproduct disposal, hazardous and solid waste disposal, protected species and other environmental matters that have the potential to impact the Company's current and future operations. The Company believes it is in material compliance with all applicable laws and regulations.

Hydroelectric Relicensing

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 dams from PacifiCorp to the KRRC. The FERC approved 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 Klamath Hydroelectric 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 transfer of the four mainstem Klamath 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. The transfer will be effective within 30 days following the issuance of a license surrender from the FERC for the project, which remains pending.

As of December 31, 2021, PacifiCorp's assets included $14 million of costs associated with the Klamath hydroelectric system's mainstem dams and the associated relicensing and settlement costs, which are being depreciated and amortized in accordance with state regulatory approvals in Utah, Wyoming and Idaho through December 31, 2022.

Hydroelectric Commitments

Certain of PacifiCorp's hydroelectric licenses contain requirements for PacifiCorp to make certain capital and operating expenditures related to its hydroelectric facilities, which are estimated to be approximately $193 million over the next 10 years. Included in these estimates are commitments associated with the KHSA.

Guarantees

The Company has entered into guarantees as part of the normal course of business and the sale 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):

	2021								
	PacifiCorp	MidAmerican Funding	NV Energy	Northern Powergrid	BHE Pipeline Group	BHE Transmission	BHE Renewables	BHE and Other[(1)]	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	796	576	2,424
Total Customer Revenue	5,255	3,514	3,083	1,066	3,416	737	796	441	18,308
Other revenue	41	33	24	122	128	(6)	185	100	627
Total	$ 5,296	$ 3,547	$ 3,107	$ 1,188	$ 3,544	$ 731	$ 981	$ 541	$ 18,935

	2020								
	PacifiCorp	MidAmerican Funding	NV Energy	Northern Powergrid	BHE Pipeline Group	BHE Transmission	BHE Renewables	BHE and Other(1)	Total
Customer Revenue:									
Regulated:									
Retail Electric	$ 4,932	$ 1,924	$ 2,566	$ —	$ —	$ —	$ —	$ (1)	$ 9,421
Retail Gas	—	505	114	—	—	—	—	—	619
Wholesale	107	199	45	—	17	—	—	(2)	366
Transmission and distribution	96	60	95	887	—	641	—	—	1,779
Interstate pipeline	—	—	—	—	1,397	—	—	(139)	1,258
Other	108	—	2	—	—	—	—	—	110
Total Regulated	5,243	2,688	2,822	887	1,414	641	—	(142)	13,553
Nonregulated	—	16	2	26	134	18	817	515	1,528
Total Customer Revenue	5,243	2,704	2,824	913	1,548	659	817	373	15,081
Other revenue	98	24	30	109	30	—	119	65	475
Total	$ 5,341	$ 2,728	$ 2,854	$ 1,022	$ 1,578	$ 659	$ 936	$ 438	$ 15,556

	2019								
	PacifiCorp	MidAmerican Funding	NV Energy	Northern Powergrid	BHE Pipeline Group	BHE Transmission	BHE Renewables	BHE and Other(1)	Total
Customer Revenue:									
Regulated:									
Retail Electric	$ 4,789	$ 1,938	$ 2,740	$ —	$ —	$ —	$ —	$ (2)	$ 9,465
Retail Gas	—	570	116	—	—	—	—	—	686
Wholesale	99	309	51	—	—	—	—	(2)	457
Transmission and distribution	98	57	98	876	—	690	—	—	1,819
Interstate pipeline	—	—	—	—	1,122	—	—	(118)	1,004
Other	—	—	2	—	—	—	—	—	2
Total Regulated	4,986	2,874	3,007	876	1,122	690	—	(122)	13,433
Nonregulated	—	30	—	36	—	17	744	577	1,404
Total Customer Revenue	4,986	2,904	3,007	912	1,122	707	744	455	14,837
Other revenue	82	23	30	101	9	—	188	101	534
Total	$ 5,068	$ 2,927	$ 3,037	$ 1,013	$ 1,131	$ 707	$ 932	$ 556	$ 15,371

(1) The BHE and Other reportable segment represents amounts related principally to other entities, including MidAmerican Energy Services, LLC, 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		
	2021	2020	2019
Customer Revenue:			
Brokerage	$ 5,498	$ 4,520	$ 4,028
Franchise	85	76	68
Total Customer Revenue	5,583	4,596	4,096
Mortgage and other revenue	632	800	377
Total	$ 6,215	$ 5,396	$ 4,473

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, 2021, by reportable segment (in millions):

	Performance obligations expected to be satisfied		
	Less than 12 months	**More than 12 months**	**Total**
BHE Pipeline Group	$ 2,607	$ 21,038	$ 23,645

(18) BHE Shareholders' Equity

Preferred Stock

As of December 31, 2021 and 2020, BHE had 1,649,988 and 3,750,000 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 has a liquidation preference of $1,000 per share and currently pays a 4.00% dividend per share on the liquidation preference. Dividends shall accrue and accumulate daily, be cumulative, compound semi-annually and, if declared, be payable in cash semi-annually in arrears on May 15 and November 15 of each year. If dividends are not declared and paid, any accumulating dividends shall continue to accumulate and compound. BHE may not make any dividends on shares of any other class or series of its capital stock (other than for dividends on shares of common stock payable in shares of common stock, unless the holders of the then outstanding 4% Perpetual Preferred Stock shall first receive, or simultaneously receive, a dividend in an amount at least equivalent to the amount accumulated and not previously paid. BHE may not declare or pay any dividends on shares of the 4% Perpetual Preferred Stock if such declaration or payment would constitute an event of default on BHE's senior indebtedness (as defined). BHE may, at its option, redeem the 4% Perpetual Preferred Stock in whole or in part at any time at a price per share equal to the liquidation preference.

Common Stock

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.

Restricted Net Assets

BHE has maximum debt-to-total capitalization percentage restrictions imposed by its senior unsecured credit facilities expiring in June 2024 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 $18.3 billion as of December 31, 2021.

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 $20.3 billion as of December 31, 2021.

(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, 2018	$ (358)	$ (1,623)	$ 36	$ —	$ (1,945)
Other comprehensive (loss) income	(59)	327	(29)	—	239
Balance, December 31, 2019	(417)	(1,296)	7	—	(1,706)
Other comprehensive (loss) income	(65)	234	(15)	—	154
BHE GT&S acquisition	(10)	—	—	10	—
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)

Reclassifications from AOCI to net income for the years ended December 31, 2021, 2020 and 2019 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 part of the GT&S Transaction, BHE acquired an indirect 25% economic interest in Cove Point, consisting of 100% of the general partnership interest and 25% of the total limited partnership interests. 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) Dominion Energy's 50% interest in Cove Point and Brookfield Super-Core Infrastructure Partner's 25% interest in Cove Point and (ii) preferred securities of subsidiaries of $58 million as of December 31, 2021 and 2020, 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

Cash and Cash Equivalents and Restricted Cash and Cash Equivalents

Cash equivalents consist of funds invested in money market mutual funds, United States 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 presented in 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,	
	2021	2020
Cash and cash equivalents	$ 1,096	$ 1,290
Restricted cash and cash equivalents	127	140
Investments and restricted cash and cash equivalents and investments	21	15
Total cash and cash equivalents and restricted cash and cash equivalents	$ 1,244	$ 1,445

The summary of supplemental cash flow disclosures as of and for the years ended December 31 is as follows (in millions):

	2021	2020	2019
Supplemental disclosure of cash flow information:			
Interest paid, net of amounts capitalized	$ 2,041	$ 1,855	$ 1,723
Income taxes received, net[(1)]	$ 1,309	$ 1,361	$ 850
Supplemental disclosure of non-cash investing and financing transactions:			
Accruals related to property, plant and equipment additions	$ 834	$ 801	$ 888

(1) Includes $1,441 million, $1,504 million and $942 million of income taxes received from Berkshire Hathaway in 2021, 2020 and 2019, 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. Information related to the Company's reportable segments is shown below (in millions):

	Years Ended December 31,		
	2021	2020	2019
Operating revenue:			
PacifiCorp	$ 5,296	$ 5,341	$ 5,068
MidAmerican Funding	3,547	2,728	2,927
NV Energy	3,107	2,854	3,037
Northern Powergrid	1,188	1,022	1,013
BHE Pipeline Group	3,544	1,578	1,131
BHE Transmission	731	659	707
BHE Renewables	981	936	932
HomeServices	6,215	5,396	4,473
BHE and Other[(1)]	541	438	556
Total operating revenue	$ 25,150	$ 20,952	$ 19,844
Depreciation and amortization:			
PacifiCorp	$ 1,088	$ 1,209	$ 954
MidAmerican Funding	914	716	638
NV Energy	549	502	482
Northern Powergrid	305	266	254
BHE Pipeline Group	492	231	115
BHE Transmission	238	201	240
BHE Renewables	241	284	282
HomeServices	52	45	47
BHE and Other[(1)]	2	1	(1)
Total depreciation and amortization	$ 3,881	$ 3,455	$ 3,011

	Years Ended December 31,		
	2021	2020	2019
Operating income:			
PacifiCorp	$ 1,133	$ 924	$ 1,072
MidAmerican Funding	416	454	549
NV Energy	621	649	655
Northern Powergrid	543	421	472
BHE Pipeline Group	1,516	779	572
BHE Transmission	339	316	323
BHE Renewables	329	291	336
HomeServices	505	511	222
BHE and Other[1]	(75)	(54)	(51)
Total operating income	5,327	4,291	4,150
Interest expense	(2,118)	(2,021)	(1,912)
Capitalized interest	64	80	77
Allowance for equity funds	126	165	173
Interest and dividend income	89	71	117
Gains (losses) on marketable securities, net	1,823	4,797	(288)
Other, net	(17)	88	97
Total income before income tax (benefit) expense and equity loss	$ 5,294	$ 7,471	$ 2,414
Interest expense:			
PacifiCorp	$ 430	$ 426	$ 401
MidAmerican Funding	319	322	302
NV Energy	206	227	229
Northern Powergrid	130	130	139
BHE Pipeline Group	143	74	52
BHE Transmission	155	148	157
BHE Renewables	158	166	174
HomeServices	4	11	25
BHE and Other[1]	573	517	433
Total interest expense	$ 2,118	$ 2,021	$ 1,912
Income tax (benefit) expense:			
PacifiCorp	$ (78)	$ (75)	$ 61
MidAmerican Funding	(680)	(574)	(377)
NV Energy	56	61	98
Northern Powergrid	192	96	59
BHE Pipeline Group	269	162	138
BHE Transmission	10	13	11
BHE Renewables[2]	(753)	(602)	(325)
HomeServices	138	138	51
BHE and Other[1]	(286)	1,089	(314)
Total income tax (benefit) expense	$ (1,132)	$ 308	$ (598)

	Years Ended December 31,		
	2021	2020	2019
Earnings on common shares:			
PacifiCorp	$ 889	$ 741	$ 773
MidAmerican Funding	883	818	781
NV Energy	439	410	365
Northern Powergrid	247	201	256
BHE Pipeline Group	807	528	422
BHE Transmission	247	231	229
BHE Renewables(2)	451	521	431
HomeServices	387	375	160
BHE and Other(1)	1,319	3,092	(467)
Total earnings on common shares	$ 5,669	$ 6,917	$ 2,950
Capital expenditures:			
PacifiCorp	$ 1,513	$ 2,540	$ 2,175
MidAmerican Funding	1,912	1,836	2,810
NV Energy	749	675	657
Northern Powergrid	742	682	602
BHE Pipeline Group	1,128	659	687
BHE Transmission	279	372	247
BHE Renewables	225	95	122
HomeServices	42	36	54
BHE and Other	21	(130)	10
Total capital expenditures	$ 6,611	$ 6,765	$ 7,364

	As of December 31,		
	2021	2020	2019
Property, plant and equipment, net:			
PacifiCorp	$ 22,914	$ 22,430	$ 20,973
MidAmerican Funding	20,302	19,279	18,377
NV Energy	10,231	9,865	9,613
Northern Powergrid	7,572	7,230	6,606
BHE Pipeline Group	15,692	15,097	5,482
BHE Transmission	6,590	6,445	6,157
BHE Renewables	6,103	5,645	5,976
HomeServices	169	159	161
BHE and Other	243	(22)	(40)
Total property, plant and equipment, net	$ 89,816	$ 86,128	$ 73,305
Total assets:			
PacifiCorp	$ 27,615	$ 26,862	$ 24,861
MidAmerican Funding	25,352	23,530	22,664
NV Energy	15,239	14,501	14,128
Northern Powergrid	9,326	8,782	8,385
BHE Pipeline Group	20,434	19,541	6,100
BHE Transmission	9,476	9,208	8,776
BHE Renewables	11,829	12,004	9,961
HomeServices	4,574	4,955	3,846
BHE and Other	8,220	7,933	1,330
Total assets	$ 132,065	$ 127,316	$ 100,051

	Years Ended December 31,		
	2021	2020	2019
Operating revenue by country:			
United States	$ 23,215	$ 19,254	$ 18,108
United Kingdom	1,188	1,022	1,011
Canada	719	653	706
Other	28	23	19
Total operating revenue by country	$ 25,150	$ 20,952	$ 19,844
Income before income tax (benefit) expense and equity loss by country:			
United States	$ 4,650	$ 6,954	$ 1,866
United Kingdom	454	338	326
Canada	181	173	178
Other	9	6	44
Total income before income tax (benefit) expense and equity loss by country:	$ 5,294	$ 7,471	$ 2,414

	As of December 31,		
	2021	2020	2019
Property, plant and equipment, net by country:			
United States	$ 75,774	$ 72,583	$ 60,634
United Kingdom	7,487	7,134	6,504
Canada	6,547	6,401	6,157
Other	8	10	10
Total property, plant and equipment, net by country	$ 89,816	$ 86,128	$ 73,305

(1) The differences between the reportable segment amounts and the consolidated amounts, described as BHE and Other, relate to other corporate entities, including MidAmerican Energy Services, LLC, 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, 2021 and 2020 (in millions):

	PacifiCorp	MidAmerican Funding	NV Energy	Northern Powergrid	BHE Pipeline Group	BHE Transmission	BHE Renewables	HomeServices	Total
December 31, 2019	$ 1,129	$ 2,102	$ 2,369	$ 978	$ 73	$ 1,520	$ 95	$ 1,456	$ 9,722
Acquisitions	—	—	—	—	1,730	—	—	1	1,731
Foreign currency translation	—	—	—	22	—	31	—	—	53
December 31, 2020	1,129	2,102	2,369	1,000	1,803	1,551	95	1,457	11,506
Acquisitions	—	—	—	—	11	—	—	129	140
Foreign currency translation	—	—	—	(8)	—	12	—	—	4
December 31, 2021	$ 1,129	$ 2,102	$ 2,369	$ 992	$ 1,814	$ 1,563	$ 95	$ 1,586	$ 11,650

PacifiCorp and its subsidiaries
Consolidated Financial Section

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

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

Results of Operations

Overview

Net income for the year ended December 31, 2021, was $888 million, an increase of $149 million, or 20%, compared to 2020, primarily due to higher utility gross margin (excluding $231 million of decreases fully offset in depreciation, operating, other income/expense and income tax expense due to prior year regulatory adjustments); lower operations and maintenance expense primarily due to prior year costs associated with the 2020 Wildfires and changes in how obligations associated with the implementation of the Klamath Hydroelectric Settlement Agreement will be met; and favorable income tax expense from higher PTCs recognized due to new wind-powered generating facilities placed in-service and the impacts of ratemaking; partially offset by higher depreciation and amortization expense (excluding $376 million of decreases offset in operating revenue and income tax expense due to prior year regulatory adjustments) from the impacts of the depreciation study for which rates became effective January 2021 and higher plant in-service; and lower allowances for equity and borrowed funds used during construction. Utility margin increased $145 million (excluding the $231 million of fully offsetting decreases) primarily due to the higher retail, wheeling and wholesale revenue; higher deferred net power costs; and lower purchased electricity volumes; partially offset by higher purchased electricity prices; and higher natural gas- and coal-fueled generation costs. Retail customer volumes increased 3.1% due to increase in customer usage, increase in the average number of customers and favorable impacts of weather. Energy generated increased 10% for 2021 compared to 2020 primarily due higher wind-powered, natural gas-fueled and coal-fueled generation, partially offset by lower hydroelectric-powered generation. Wholesale electricity sales volumes decreased 3% and purchased electricity volumes decreased 17%.

Net income for the year ended December 31, 2020 was $739 million, a decrease of $32 million, or 4%, compared to 2019, primarily due to costs associated with the 2020 Wildfires and the Klamath Hydroelectric Project of $169 million; higher net interest expense of $36 million from higher long-term debt and lower cash balances; higher pension and other postretirement costs of $13 million; and higher property taxes of $10 million; partially offset by lower income tax expense of $99 million (excluding $37 million fully offset primarily in depreciation expense) primarily driven by higher PTCs substantially due to repowered wind-powered generating facilities and lower pre-tax income; higher utility margin of $47 million (excluding $231 million of increases fully offset in depreciation, operating, other income/expense and income tax expense as a result of regulatory adjustments as ordered by the UPSC, the OPUC and the IPUC); higher allowances for equity and borrowed funds used during construction of $38 million; and prior year costs associated with the early retirement of a coal-fueled generation unit totaling $24 million. Utility margin increased primarily due to lower coal-fueled generation volumes, lower purchased electricity prices, higher average retail rates and lower natural gas-fueled generation costs, partially offset by lower net deferrals of incurred net power costs in accordance with established adjustment mechanisms, lower retail customer volumes and higher purchased electricity volumes. Retail customer volumes decreased 1.4% primarily due to impacts of COVID-19, which resulted in lower industrial and commercial customer usage and higher residential customer usage, partially offset by an increase in the average number of residential and commercial customers and the favorable impact of weather. Energy generated decreased 4% for 2020 compared to 2019 primarily due to lower coal-fueled generation, partially offset by higher wind and hydroelectric-powered generation. Wholesale electricity sales volumes decreased 4% and purchased electricity volumes increased 9%.

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):

	2021	2020	Change		2020	2019	Change	
Utility margin:								
Operating revenue	$ 5,296	$ 5,341	$ (45)	(1)%	$ 5,341	$ 5,068	$ 273	5 %
Cost of fuel and energy	1,831	1,790	41	2	1,790	1,795	(5)	—
Utility margin	3,465	3,551	(86)	(2)	3,551	3,273	278	8
Operations and maintenance	1,031	1,209	(178)	(15)	1,209	1,048	161	15
Depreciation and amortization	1,088	1,209	(121)	(10)	1,209	954	255	27
Property and other taxes	213	209	4	2	209	199	10	5
Operating income	$ 1,133	$ 924	$ 209	23 %	$ 924	$ 1,072	$ (148)	(14)%

Utility Margin

A comparison of key operating results related to utility margin is as follows for the years ended December 31:

	2021	2020	Change		2020	2019	Change	
Utility margin (in millions):								
Operating revenue	$ 5,296	$ 5,341	$ (45)	(1)%	$ 5,341	$ 5,068	$ 273	5 %
Cost of fuel and energy	1,831	1,790	41	2	1,790	1,795	(5)	—
Utility margin	$ 3,465	$ 3,551	$ (86)	(2)%	$ 3,551	$ 3,273	$ 278	8 %
Sales (GWhs):								
Residential	17,905	17,150	755	4 %	17,150	16,668	482	3 %
Commercial[1]	18,839	17,727	1,112	6	17,727	18,151	(424)	(2)
Industrial[1]	17,909	18,039	(130)	(1)	18,039	19,049	(1,010)	(5)
Other[1]	1,621	1,644	(23)	(1)	1,644	1,475	169	11
Total retail	56,274	54,560	1,714	3	54,560	55,343	(783)	(1)
Wholesale	5,113	5,249	(136)	(3)	5,249	5,480	(231)	(4)
Total sales	61,387	59,809	1,578	3 %	59,809	60,823	(1,014)	(2)%
Average number of retail customers (in thousands)	2,003	1,967	36	2 %	1,967	1,933	34	2 %
Average revenue per MWh:								
Retail	$ 86.08	$ 90.59	$ (4.51)	(5)%	$ 90.59	$ 84.80	$ 5.79	7 %
Wholesale	$ 37.90	$ 35.56	$ 2.34	7 %	$ 35.56	$ 35.21	$ 0.35	1 %
Heating degree days	9,914	10,155	(241)	(2)%	10,155	11,143	(988)	(9)%
Cooling degree days	2,431	2,111	320	15 %	2,111	1,773	338	19 %
Sources of energy (GWhs)[1]:								
Coal	31,566	30,636	930	3 %	30,636	34,510	(3,874)	(11)%
Natural gas	13,323	12,045	1,278	11	12,045	12,058	(13)	—
Wind[2]	6,686	3,769	2,917	77	3,769	2,266	1,503	66
Hydroelectric and other[2]	3,010	3,223	(213)	(7)	3,223	2,961	262	9
Total energy generated	54,585	49,673	4,912	10	49,673	51,795	(2,122)	(4)
Energy purchased	11,601	14,054	(2,453)	(17)	14,054	12,906	1,148	9
Total	66,186	63,727	2,459	4 %	63,727	64,701	(974)	(2)%
Average cost of energy per MWh:								
Energy generated[3]	$ 18.05	$ 18.74	$ (0.69)	(4)%	$ 18.74	$ 19.36	$ (0.62)	(3)%
Energy purchased	$ 66.93	$ 47.60	$ 19.33	41 %	$ 47.60	$ 54.20	$ (6.60)	(12)%

(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, 2021 Compared to Year Ended December 31, 2020

Utility margin decreased $86 million (including the $231 million of fully offsetting decreases) for 2021 compared to 2020 primarily due to:

- $111 million of higher purchased electricity costs due to higher average prices, partially offset by lower volumes;
- $99 million of lower retail revenue primarily due to $234 million fully offset in depreciation expense, income tax expense, fuel expense, and other income (expense) due to accelerated depreciation of certain coal-fueled units in Utah and Oregon and recognition of certain Utah regulatory balances in the prior year, and lower average retail prices, partially offset by higher retail customer volumes. Retail customer volumes increased 3.1% due to an increase in residential and commercial customer usage, increase in the average number of customers and favorable impacts of weather, primarily in Oregon, Washington and Idaho;
- $88 million of higher natural gas-fueled generation costs primarily due to higher average prices and higher volumes; and
- $34 million of lower other revenue due to prior year recognition of prior OATT revenue related deferrals in Oregon used to accelerate the depreciation of certain retired wind equipment as a result of the 2020 Oregon RAC settlement (offset in depreciation expense).

The decreases above were partially offset by:

- $141 million primarily from higher deferred net power costs in accordance with established adjustment mechanisms;
- $43 million of favorable wheeling activities;
- $33 million of lower coal-fueled generation costs primarily due to $37 million of accelerated recognition of certain Utah regulatory balances associated with the 2015 Utah mine disposition and certain Cholla Unit 4 related closure costs in Oregon and Idaho (offset in income tax expense) in the prior year and lower prices, partially offset by higher volumes;
- $19 million of higher other revenue primarily due to higher REC, fly ash and by-product revenues; and
- $7 million of higher wholesale revenue due to higher average wholesale market prices, partially offset by lower wholesale volumes.

Operations and maintenance decreased $178 million, or 15%, for 2021 compared to 2020 primarily due to prior year estimated losses associated with the 2020 Wildfires of $136 million, net of expected insurance recoveries, changes in how obligations associated with the implementation of the Klamath Hydroelectric Settlement Agreement will be met, lower thermal plant maintenance expense and lower labor expenses, partially offset by higher wind plant and distribution maintenance and higher legal and insurance expenses associated with the 2020 Wildfires.

Depreciation and amortization decreased $121 million, or 10%, for 2021 compared to 2020 primarily due to prior year accelerated depreciation of $376 million as a result of regulatory adjustments ordered by the UPSC, the OPUC and the IPUC (fully offset in retail revenue, other revenue, and income tax expense), including accelerated depreciation of certain coal-fueled units and Oregon's share of certain retired wind equipment as a result the 2020 Oregon RAC settlement, partially offset by the impacts of the depreciation study for which rates became effective January 1, 2021 of approximately $158 million and higher plant in-service balances.

Property and other taxes increased $4 million, or 2%, for 2021 compared to 2020 primarily due to higher property taxes in Oregon and Wyoming, partially offset by lower property taxes in Utah and Washington.

Interest expense increased $4 million, or 1%, for 2021 compared to 2020 primarily due to higher average long-term debt balances, partially offset by a lower weighted average long-term debt interest rate.

Allowance for borrowed and equity funds decreased $72 million, or 49%, for 2021 compared to 2020 primarily due to lower qualified construction work-in-progress balances.

Interest and dividend income increased $14 million, or 140%, for 2021 compared to 2020 primarily due to higher carrying charges on DSM regulatory assets in the current year.

Income tax benefit increased $4 million, or 5%, for 2021 compared to 2020. The effective tax rate was (10)% and (11)% for 2021 and 2020, respectively. The effective tax rate increased primarily as a result of lower effects of ratemaking associated with excess deferred income tax amortization, offset by increased PTCs from PacifiCorp's new wind-powered generating facilities in the current year. In 2020, $118 million of excess deferred income taxes was amortized pursuant to regulatory orders from Utah, Oregon and Idaho, whereby portions of excess deferred income taxes were used to accelerate depreciation of certain coal-fueled units and Oregon's share of certain retired wind equipment or offset other regulatory balances for these jurisdictions.

Year Ended December 31, 2020 Compared to Year Ended December 31, 2019

Utility margin increased $278 million for 2020 compared to 2019 primarily due to:

- $249 million increase in retail revenue, including $234 million fully offset in depreciation expense and income tax expense due to accelerated depreciation of certain coal-fueled units in Utah and Oregon and recognition of certain Utah regulatory balances and higher average retail prices, partially offset by lower retail customer volumes. Retail customer volumes decreased 1.4% primarily due to impacts of COVID-19, which resulted in lower industrial and commercial customer usage and higher residential customer usage, partially offset by an increase in the average number of residential and commercial customers and the favorable impact of weather;

- $49 million of lower coal-fueled generation costs primarily due to lower volumes of $78 million, partially offset by $37 million of accelerated recognition of certain Utah regulatory balances associated with the 2015 Utah mine disposition and certain Cholla Unit 4 related closure costs in Oregon and Idaho (offset in income tax expense) and higher prices of $9 million;
- $34 million of higher other revenue due to recognition of prior OATT revenue related deferrals in Oregon used to accelerate the depreciation of certain retired wind equipment as a result of the 2020 Oregon RAC settlement (offset in depreciation expense);
- $31 million of lower purchased electricity costs, primarily due to lower average market prices, partially offset by higher volumes; and
- $24 million of lower natural gas-fueled generation costs primarily due to lower average prices and lower volumes.

The increases above were partially offset by:

- $106 million primarily from lower deferrals and higher amortization of previous deferrals of incurred net power costs in accordance with established adjustment mechanisms.

Operations and maintenance increased $161 million, or 15%, for 2020 compared to 2019 primarily due to costs associated with the 2020 Wildfires of $136 million, net of expected insurance recoveries, and costs associated with the Klamath Hydroelectric Project of $33 million, higher vegetation management and wildfire mitigation costs of $26 million and increased bad debt expense of $5 million, partially offset by prior year costs associated with the early retirement of Cholla Unit 4 of $24 million and lower employee related expenses of $7 million as a result of COVID-19.

Depreciation and amortization increased $255 million, or 27%, for 2020 compared to 2019 primarily due to current year accelerated depreciation of $376 million as a result of regulatory adjustments ordered by the UPSC, the OPUC and the IPUC (fully offset in retail revenue, other revenue, and income tax expense), including accelerated depreciation of certain coal-fueled units and Oregon's share of certain retired wind equipment as a result the 2020 Oregon RAC settlement, partially offset by prior year accelerated depreciation of $120 million (offset in income tax expense) on Oregon's share of certain retired wind equipment due to repowering as a result of the 2019 Oregon RAC settlement.

Property and other taxes increased $10 million, or 5%, for 2020 compared to 2019 primarily due to higher property taxes in Oregon and Utah.

Interest expense increased $25 million, or 6%, for 2020 compared to 2019 primarily due to higher average long-term debt balances, partially offset by a lower weighted average long-term debt interest rate.

Allowance for borrowed and equity funds increased $38 million, or 35%, for 2020 compared to 2019 primarily due to higher qualified construction work-in-progress balances.

Interest and dividend income decreased $11 million, or 52%, for 2020 compared to 2019 primarily due to lower average interest rates in the current year.

Other, net decreased $22 million, or 69% for 2020 compared to 2019 primarily due to higher pension and post retirement costs of $13 million and costs associated with the recognition of Utah's share of the post retirement settlement loss associated with the 2015 Utah mine disposition (offset in income tax expense).

Income tax (benefit) expense decreased $136 million to a benefit of $75 million for 2020 compared to an expense of $61 million for 2019. The effective tax rate was (11)% and 7% for 2020 and 2019, respectively. The effective tax rate decreased primarily as a result of higher amortization of excess deferred income taxes in 2020 and higher PTCs. In 2020, $118 million of excess deferred income taxes was amortized pursuant to regulatory orders from Utah, Oregon and Idaho, whereby portions of excess deferred income taxes were used to accelerate depreciation of certain coal-fueled units and Oregon's share of certain retired wind equipment or offset other regulatory balances for these jurisdictions. In 2019, $91 million of Oregon's allocated excess deferred income taxes was amortized pursuant to the 2019 Oregon RAC proceeding, whereby a portion of Oregon's allocated excess deferred income taxes was used to accelerate depreciation for Oregon's share of certain retired wind equipment due to repowering.

Liquidity and Capital Resources

As of December 31, 2021, PacifiCorp's total net liquidity was as follows (in millions):

Cash and cash equivalents	$	179
Credit facilities[(1)]		1,200
Less:		
Tax-exempt bond support		(218)
Net credit facilities		982
Total net liquidity	$	1,161
Credit facilities:		
Maturity dates		2024

(1) Refer to Note 7 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for further discussion regarding PacifiCorp's credit facilities.

Operating Activities

Net cash flows from operating activities for the years ended December 31, 2021 and 2020 were $1.8 billion and $1.6 billion, respectively. The increase is primarily due to higher cash received for income taxes and higher collections from retail customers, partially offset by higher wholesale purchases and timing of operating payables.

Net cash flows from operating activities for the years ended December 31, 2020 and 2019 were $1.6 billion and $1.5 billion, respectively. The increase is primarily due to lower purchased power prices, lower cash paid for income taxes and lower operating expense payments due to timing, partially offset by lower collections from wholesale and retail customers and higher fuel expense payments due to timing.

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, 2021 and 2020 were $(1.5) billion and $(2.5) billion, respectively. The decrease in net cash outflows from investing activities is mainly due to a decrease in capital expenditures of $1.0 billion.

Net cash flows from investing activities for the years ended December 31, 2020 and 2019 were $(2.5) billion and $(2.2) billion, respectively. The increase in net cash outflows from investing activities is mainly due to an increase in capital expenditures of $365 million, partially offset by proceeds from the settlement of notes receivable of $25 million associated with the sale of certain Utah mining assets in 2015.

Financing Activities

Short-term Debt

Regulatory authorities limit PacifiCorp to $1.5 billion of short-term debt. As of December 31, 2021, PacifiCorp had no short-term debt outstanding. As of December 31, 2020, PacifiCorp had $93 million of short-term debt outstanding at a weighted average interest rate of 0.16%. For further discussion, refer to Note 7 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Long-term Debt

In November 2021, PacifiCorp exercised its par call redemption option, available in the final three months prior to scheduled maturity, and redeemed $450 million of its 2.95% Series First Mortgage Bonds that was originally due February 2022.

In July 2021, PacifiCorp issued $1 billion of its 2.90% First Mortgage Bonds due June 2052. PacifiCorp used the net proceeds to finance a portion of the capital expenditures disbursed during the period from July 1, 2019 to May 31, 2021 with respect to investments, primarily from the Energy Vision 2020 initiative, in the repowering of certain of its existing wind-powered generating facilities and the construction and acquisition of new wind-powered generating facilities, which were previously financed with PacifiCorp's general funds.

PacifiCorp made repayments on long-term debt totaling $870 million and $38 million during the years ended December 31, 2021 and 2020, respectively.

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, 2021, PacifiCorp estimated it would be able to issue up to $11.8 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. 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.

Credit Facilities

In June 2021, PacifiCorp terminated, upon lender consent, its existing $600 million unsecured credit facility expiring in June 2022. In June 2021, PacifiCorp amended and restated its other existing $600 million unsecured credit facility expiring in June 2022 with one remaining one-year extension option. The amendment increased the lender commitment to $1.2 billion, extended the expiration date to June 2024 and increased the available maturity extension options to an unlimited number, subject to lender consent.

In 2020, PacifiCorp's credit facility support for outstanding variable rate tax-exempt bond obligations decreased by $38 million due to maturities.

Debt Authorizations

PacifiCorp currently has regulatory authority from the OPUC and the IPUC to issue an additional $2 billion of long-term debt. PacifiCorp must make a notice filing with the WUTC prior to any future issuance. PacifiCorp currently has an effective shelf registration statement with the SEC to issue an indeterminate amount of first mortgage bonds through September 2023.

Preferred Stock

As of December 31, 2021 and 2020, PacifiCorp had non-redeemable preferred stock outstanding with an aggregate stated value of $2 million.

Common Shareholder's Equity

In 2021 and 2020, PacifiCorp declared and paid dividends of $150 million and $— million, respectively, to PPW Holdings LLC.

Capitalization

PacifiCorp manages its capitalization and liquidity position to maintain a prudent capital structure with an 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, 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 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.

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**		
	2019	**2020**	**2021**	**2022**	**2023**	**2024**
Wind generation	$ 933	$ 1,277	$ 131	$ 210	$ 473	$ 440
Electric distribution	413	613	618	610	586	515
Electric transmission	612	405	315	927	1,617	836
Other	217	245	449	254	641	710
Total	$ 2,175	$ 2,540	$ 1,513	$ 2,001	$ 3,317	$ 2,501

PacifiCorp's 2019 and 2021 IRPs identified a roadmap for a significant increase in renewable and carbon free generation resources, coal to natural gas conversion of certain coal-fueled units, energy storage and associated transmission. Similar to PacifiCorp's 2019 IRP, the 2021 IRP identified over 1,800 MWs of new wind-powered generating resources that are expected to be online by 2025. PacifiCorp anticipates that the additional new wind-powered generation will be a mixture of owned and contracted resources. PacifiCorp has included an estimate for these new generation resources and associated transmission in its forecast capital expenditures for 2022 through 2024. These estimates are likely to change as a result of the 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 wind-powered generating facilities at PacifiCorp totaled $107 million for 2021, $1,148 million for 2020 and $338 million for 2019. Construction includes 674 MWs of new wind-powered generating facilities that were placed in-service in 2020 and 516 MWs that were placed in-service in 2021. Planned spending for the construction of additional wind-powered generating facilities totals $131 million in 2022, $405 million in 2023 and $373 million in 2024.
    - Repowering of existing wind-powered generating facilities at PacifiCorp totaled $9 million in 2021, $125 million in 2020 and $585 million in 2019. All existing wind-powered generating facilities at PacifiCorp have been repowered as of December 31, 2021.
    - The 2021 IRP also included PacifiCorp's planned acquisition and repowering of two wind-powered generating facilities. The repowered facilities are expected to be placed in-service in 2023 and 2024. PacifiCorp spent $11 million in 2021 and planned spending for acquiring and repowering generating facilities totals $60 million in 2022, $36 million in 2023 and $34 million in 2024.
- Electric distribution includes both growth projects and operating expenditures. Operating expenditures includes spend on wildfire mitigation and wildfire and storm damage restoration. Expenditures for these items totaled $176 million in 2021, $187 million in 2020 and $4 million in 2019, and planned spending totals $153 million in 2022, $133 million in 2023 and $127 million in 2024. Remaining investments relate to expenditures for new connections and distribution operations.
- Electric transmission includes both growth projects and operating expenditures. Transmission investment in 2021 through 2024 primarily reflects planned costs for the 416-mile, 500-kV high-voltage transmission line between the Aeolus substation near Medicine Bow in 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; and the 290-mile, 500-kV high-voltage transmission line from the Longhorn substation near Boardman, Oregon to the Hemingway substation near Boise, Idaho. PacifiCorp is advancing permitting and regulatory approvals related to the projects. Planned spending for these Energy Gateway Transmission segments to be placed in-service in 2024-2026 totals $565 million in 2022, $1,143 million in 2023, and $437 million in 2024.
- Other includes both growth projects and operating expenditures. Expenditures for information technology totaled $108 million in 2021, $75 million in 2020 and $62 million for 2019. Planned information technology spending totals $167 million in 2022, $163 million in 2023 and $136 million in 2024. Remaining investments relate to operating projects that consist of routine expenditures for generation and other infrastructure needed to serve existing and expected demand.

<u>Off-Balance Sheet Arrangements</u>

PacifiCorp from time to time 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), purchased electricity contracts (refer to Note 14), fuel contracts (refer to Note 14), cost of removal and AROs (refer to Notes 6 and 11), construction and other development costs (refer to Liquidity and Capital Resources included within this Item 7). 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 $6.5 billion on long-term debt, including $400 million due in 2022.

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 climate change, wildfire prevention and mitigation, RPS, air and water quality, emissions performance standards, coal combustion byproduct disposal, hazardous and solid waste disposal, protected species 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 additional information 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, 2021, PacifiCorp'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.

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 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 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, 2021, PacifiCorp would have been required to post $218 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, 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 structure administered by various state commissions and the FERC. Under this rate 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.

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 the 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 $1.4 billion and total regulatory liabilities were $2.8 billion as of December 31, 2021. 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, 2021, PacifiCorp recognized a net asset totaling $46 million for the funded status of its defined benefit pension and other postretirement benefit plans. As of December 31, 2021, amounts not yet recognized as a component of net periodic benefit cost that were included in net regulatory assets and accumulated other comprehensive loss totaled $260 million and $23 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 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 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, 2021.

PacifiCorp chooses a discount rate based upon high quality debt security investment yields in effect as of the measurement date with cash flows aligning to the expected timing and amount of plan liabilities. The pension and other postretirement benefit liabilities increase as the discount rate is reduced.

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

The key assumptions used may differ materially from period to period due to changing market and economic conditions. These differences may result in a significant impact to pension and other postretirement benefits expense and the 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, 2021 Benefit Obligations:				
Discount rate	$ (50)	$ 55	$ (13)	$ 15
Effect on 2021 Periodic Cost:				
Discount rate	$ —	$ —	$ 1	$ (1)
Expected rate of return on plan assets	(5)	5	(2)	2

A variety of factors affect the funded status of the plans, including asset returns, discount rates, 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, if any, 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 benefits and expense related to the federal tax rate change from 35% to 21% as a result of 2017 Tax Reform, certain property-related basis differences and other various differences on to their customers in certain state jurisdictions. As of December 31, 2021, these amounts were recognized as a net regulatory liability of $1.3 billion and will be included in regulated rates when the temporary differences reverse.

Revenue Recognition - Unbilled Revenue

Revenue is recognized as electricity is delivered or services are provided. 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. Unbilled revenue was $264 million as of December 31, 2021. 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. Estimates are reversed in the following month and actual revenue is recorded based on subsequent meter readings.

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 PacifiCorp's 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.

<u>Commodity Price Risk</u>

PacifiCorp is principally exposed to electricity, natural gas, coal and fuel oil commodity price risk as PacifiCorp 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, 2021.

The table that follows summarizes PacifiCorp's price risk on commodity contracts accounted for as derivatives, excluding collateral netting of $5 million and $24 million as of December 31, 2021 and 2020, 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, 2021:			
Total commodity derivative contracts	$ 53	$ 104	$ 2
As of December 31, 2020:			
Total commodity derivative contracts	$ (17)	$ 5	$ (39)

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, 2021 and 2020, a regulatory liability of $53 million and a regulatory asset of $17 million, respectively, was recorded related to the net derivative asset of $53 million and a net derivative liability of $17 million, respectively. Consolidated financial results would be negatively impacted if the costs of wholesale electricity, natural gas or fuel are higher or the level of wholesale electricity sales are lower than what is included in rates, including the impacts of adjustment mechanisms.

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 may from time to time 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, 2021 and 2020, PacifiCorp had short- and long-term variable-rate obligations totaling $218 million and $310 million, respectively that expose PacifiCorp to the risk of increased interest expense in the event of increases in short-term interest rates. The market risk related to PacifiCorp's variable-rate debt as of December 31, 2021 is not hedged. If variable interest rates were to increase by 10% from December 31 levels, it would not have a material effect on PacifiCorp's consolidated annual interest expense. The carrying value of the variable-rate obligations approximates fair value as of December 31, 2021 and 2020.

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, 2021, 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	211
Consolidated Balance Sheets	214
Consolidated Statements of Operations	216
Consolidated Statements of Comprehensive Income	217
Consolidated Statements of Changes in Shareholders' Equity	218
Consolidated Statements of Cash Flows	219
Notes to Consolidated Financial Statements	220

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, 2021 and 2020, the related consolidated statements of operations, comprehensive income, changes in shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2021, 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, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021, 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 — Impact of Rate Regulation on the Financial Statements — Refer to Notes 2 and 6 to the financial statements

Critical Audit Matter Description

PacifiCorp 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 rates in the respective service territories where PacifiCorp operates. Management has determined it meets 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 impacts multiple financial statement line items and disclosures, such as property, plant, and equipment, net; regulatory assets and liabilities; deferred income taxes; operating revenue; operations and maintenance expense; depreciation and amortization expense; and income tax expense (benefit).

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 impact 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 impact of rate regulation as a critical audit matter due to the significant judgments made by management to support its assertions about impacted account balances and disclosures and the high degree of subjectivity involved in assessing the impact of future 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 future 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 PacifiCorp's disclosures related to the impacts of rate regulation, including the balances recorded and regulatory developments.
- We read relevant regulatory orders issued by the Commissions, regulatory statutes, interpretations, procedural memorandums, filings made by interveners, and other publicly available information 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 evaluated the external information and compared to management's recorded regulatory asset and liability balances for completeness.
- For regulatory matters in process, we inspected PacifiCorp's filings with the Commissions and the filings with the Commissions by intervenors that may impact PacifiCorp's future rates, for any evidence that might contradict management's assertions.

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.

California and Oregon 2020 Wildfires – Contingencies – See Note 14 to the financial statements

Critical Audit Matter Description

PacifiCorp has loss contingencies related to the California and Oregon 2020 wildfires (the "2020 wildfires"). PacifiCorp has recorded estimated liabilities, net of expected insurance recoveries, of $136 million as of December 31, 2021, which represents its best estimate of probable losses, net of expected insurance recoveries, as a result of the 2020 wildfires.

We identified wildfire-related contingencies and the related disclosure as a critical audit matter because of the significant judgments made by management to estimate the losses. This required the application of a high degree of judgment and extensive effort when performing audit procedures to evaluate the reasonableness of management's estimate of the losses and disclosure related to wildfire-related loss contingencies.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to management's judgments regarding its estimate of losses for wildfire-related contingencies and the related disclosure included the following, among others:

- We evaluated management's judgments related to whether a loss was probable and reasonably estimable, reasonably possible, or remote for each individual wildfire by inquiring of management and PacifiCorp's external and internal legal counsel regarding the amounts of probable and reasonably estimable, reasonably possible, and remote losses, including the potential impact of information gained through management's and its external and internal legal counsel's ongoing investigations into the causes of each fire, and external information for any evidence that might contradict management's assertions.
- We evaluated the estimation methodology for determining the amount of probable loss through inquiries with management and its external and internal legal counsel.

- We tested the significant assumptions used in determining the estimate, including, but not limited to, information gained through management's and its external and internal legal counsel's ongoing investigations into the causes of each fire.
- We read legal letters from PacifiCorp's external and internal legal counsel regarding information regarding ongoing litigation related to the 2020 wildfires and evaluated whether the information therein was consistent with the information obtained in our procedures.
- We evaluated whether PacifiCorp's disclosures were appropriate and consistent with the information obtained in our procedures.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 25, 2022

We have served as PacifiCorp's auditor since 2006.

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Amounts in millions)

	As of December 31,	
	2021	**2020**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 179	$ 13
Trade receivables, net	725	703
Other receivables, net	52	48
Inventories	474	482
Regulatory assets	65	116
Prepaid expenses	79	79
Other current assets	147	82
Total current assets	1,721	1,523
Property, plant and equipment, net	22,914	22,430
Regulatory assets	1,287	1,279
Other assets	534	470
Total assets	$ 26,456	$ 25,702

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,	
LIABILITIES AND SHAREHOLDERS' EQUITY	**2021**	**2020**
Current liabilities:		
Accounts payable	$ 680	$ 772
Accrued interest	121	127
Accrued property, income and other taxes	78	80
Accrued employee expenses	89	84
Short-term debt	—	93
Current portion of long-term debt	155	420
Regulatory liabilities	118	115
Other current liabilities	219	174
Total current liabilities	1,460	1,865
Long-term debt	8,575	8,192
Regulatory liabilities	2,650	2,727
Deferred income taxes	2,847	2,627
Other long-term liabilities	1,011	1,118
Total liabilities	16,543	16,529
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	5,449	4,711
Accumulated other comprehensive loss, net	(17)	(19)
Total shareholders' equity	9,913	9,173
Total liabilities and shareholders' equity	$ 26,456	$ 25,702

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,		
	2021	**2020**	**2019**
Operating revenue	$ 5,296	$ 5,341	$ 5,068
Operating expenses:			
Cost of fuel and energy	1,831	1,790	1,795
Operations and maintenance	1,031	1,209	1,048
Depreciation and amortization	1,088	1,209	954
Property and other taxes	213	209	199
Total operating expenses	4,163	4,417	3,996
Operating income	1,133	924	1,072
Other income (expense):			
Interest expense	(430)	(426)	(401)
Allowance for borrowed funds	24	48	36
Allowance for equity funds	50	98	72
Interest and dividend income	24	10	21
Other, net	8	10	32
Total other expense	(324)	(260)	(240)
Income before income tax (benefit) expense	809	664	832
Income tax (benefit) expense	(79)	(75)	61
Net income	$ 888	$ 739	$ 771

The accompanying notes are an integral part of these consolidated financial statements.

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Amounts in millions)

	Years Ended December 31,		
	2021	2020	2019
Net income	$ 888	$ 739	$ 771
Other comprehensive income (loss), net of tax —			
Unrecognized amounts on retirement benefits, net of tax of $1, $(1) and $(1)	2	(3)	(3)
Comprehensive income	$ 890	$ 736	$ 768

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, 2018	$ 2	$ —	$ 4,479	$ 3,377	$ (13)	$ 7,845
Net income	—	—	—	771	—	771
Other comprehensive loss	—	—	—	(1)	(3)	(4)
Common stock dividends declared	—	—	—	(175)	—	(175)
Balance, December 31, 2019	2	—	4,479	3,972	(16)	8,437
Net income	—	—	—	739	—	739
Other comprehensive loss	—	—	—	—	(3)	(3)
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

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,		
	2021	**2020**	**2019**
Cash flows from operating activities:			
Net income	$ 888	$ 739	$ 771
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	1,088	1,209	954
Allowance for equity funds	(50)	(98)	(72)
Changes in regulatory assets and liabilities	(189)	(229)	(55)
Deferred income taxes and amortization of investment tax credits	64	(124)	(131)
Other, net	(5)	1	20
Changes in other operating assets and liabilities:			
Trade receivables, other receivables and other assets	15	(154)	26
Inventories	8	(88)	23
Prepaid expenses	2	(15)	(12)
Derivative collateral, net	19	23	12
Accrued property, income and other taxes, net	(37)	(53)	22
Accounts payable and other liabilities	1	372	(11)
Net cash flows from operating activities	1,804	1,583	1,547
Cash flows from investing activities:			
Capital expenditures	(1,513)	(2,540)	(2,175)
Other, net	12	30	11
Net cash flows from investing activities	(1,501)	(2,510)	(2,164)
Cash flows from financing activities:			
Proceeds from long-term debt	984	987	989
Repayments of long-term debt	(870)	(38)	(350)
(Repayments of) net proceeds from short-term debt	(93)	(37)	100
Dividends paid	(150)	—	(175)
Other, net	(7)	(2)	(3)
Net cash flows from financing activities	(136)	910	561
Net change in cash and cash equivalents and restricted cash and cash equivalents	167	(17)	(56)
Cash and cash equivalents and restricted cash and cash equivalents at beginning of period	19	36	92
Cash and cash equivalents and restricted cash and cash equivalents at end of period	$ 186	$ 19	$ 36

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 United States 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, including those related to the Oregon and Northern California 2020 wildfires (the "2020 Wildfires") described 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 in 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 Equivalents and Restricted Cash and Cash Equivalents and Investments

Cash equivalents consist of funds invested in money market mutual funds, United States 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, custodial and nuclear decommissioning funds. Restricted amounts are included in other current assets and other assets on the Consolidated Balance Sheets.

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, 2021 and 2020, 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 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):

	2021	2020	2019
Beginning balance	$ 17	$ 8	$ 8
Charged to operating costs and expenses, net	13	18	13
Write-offs, net	(12)	(9)	(13)
Ending balance	$ 18	$ 17	$ 8

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 energy costs 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 the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value and any resulting impairment loss is reflected on the Consolidated Statements of Operations. As substantially all property, plant and equipment supports PacifiCorp's regulated businesses 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. Other revenue consists primarily of revenue recognized in accordance with ASC 815, "Derivatives and Hedging."

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. As of December 31, 2021 and 2020, trade receivables, net on the Consolidated Balance Sheets relate substantially to Customer Revenue, including unbilled revenue of $264 million and $254 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 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 United States 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 that are associated with components of OCI are charged or credited directly to OCI. Changes in deferred income tax assets and liabilities that are 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 generally 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.

(3) Property, Plant and Equipment, Net

Property, plant and equipment, net consists of the following as of December 31 (in millions):

	Depreciable Life	2021	2020
Utility Plant:			
Generation	15 - 59 years	$ 13,679	$ 12,861
Transmission	60 - 90 years	7,894	7,632
Distribution	20 - 75 years	8,044	7,660
Intangible plant[(1)]	5 - 75 years	1,106	1,054
Other	5 - 60 years	1,539	1,510
Utility plant in-service		32,262	30,717
Accumulated depreciation and amortization		(10,507)	(9,838)
Utility plant in-service, net		21,755	20,879
Other non-regulated, net of accumulated depreciation and amortization	14 - 95 years	18	9
Plant, net		21,773	20,888
Construction work-in-progress		1,141	1,542
Property, plant and equipment, net		$ 22,914	$ 22,430

(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 3.5%, 4.1% and 3.3% for the years ended December 31, 2021, 2020 and 2019, respectively, including the impacts of accelerated depreciation totaling $376 million and $125 million in 2020 and 2019, respectively, for Utah's share of certain thermal plant units in 2020, including Cholla Unit No. 4 in 2020 for which operations ceased in December 2020; Oregon's and Idaho's shares of Cholla Unit No. 4 in 2020; and Oregon's share of certain retired wind equipment associated with wind repowering projects in 2020 and 2019. As discussed in Notes 6 and 9, existing regulatory liabilities primarily associated with the Utah Sustainability and Transportation Plan ("STEP") and 2017 Tax Reform benefits were utilized to accelerate depreciation of these assets.

Effective January 1, 2021, PacifiCorp revised its depreciation rates based on its recent depreciation study that was approved by its state regulatory commissions, other than in California. The approved depreciation rates resulted in an increase in depreciation expense of approximately $158 million for the year ended December 31, 2021, as compared to the year ended December 31, 2020, based on historical property, plant and equipment balances and including depreciation of certain coal-fueled generating units in Washington over accelerated periods.

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, 2021 and 2020, and accumulated depreciation of $143 million and $140 million as of December 31, 2021 and 2020, 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, 2021 (dollars in millions):

	PacifiCorp Share	Facility in Service	Accumulated Depreciation and Amortization	Construction Work-in-Progress
Jim Bridger Nos. 1 - 4	67 %	$ 1,523	$ 812	$ 15
Hunter No. 1	94	489	221	8
Hunter No. 2	60	306	138	1
Wyodak	80	477	269	8
Colstrip Nos. 3 and 4	10	260	161	3
Hermiston	50	185	99	—
Craig Nos. 1 and 2	19	369	319	—
Hayden No. 1	25	77	47	—
Hayden No. 2	13	44	28	—
Transmission and distribution facilities	Various	879	269	118
Total		$ 4,609	$ 2,363	$ 153

(5) Leases

The following table summarizes PacifiCorp's leases recorded on the Consolidated Balance Sheets as of December 31 (in millions):

	2021	2020
Right-of-use assets:		
Operating leases	$ 11	$ 11
Finance leases	11	17
Total right-of-use assets	$ 22	$ 28
Lease liabilities:		
Operating leases	$ 11	$ 11
Finance leases	12	17
Total lease liabilities	$ 23	$ 28

The following table summarizes PacifiCorp's lease costs for the years ended December 31 (in millions):

	2021	2020	2019
Variable	$ 56	$ 60	$ 77
Operating	3	3	3
Finance:			
Amortization	5	2	1
Interest	2	2	2
Short-term	3	1	2
Total lease costs	$ 69	$ 68	$ 85
Weighted-average remaining lease term (years):			
Operating leases	12.7	13.9	14.0
Finance leases	10.1	8.4	9.1
Weighted-average discount rate:			
Operating leases	3.7 %	3.8 %	3.7 %
Finance leases	11.1 %	10.5 %	10.6 %

Cash payments associated with operating and finance lease liabilities approximated lease cost for the years ended December 31, 2021, 2020 and 2019.

PacifiCorp has the following remaining lease commitments as of December 31, 2021 (in millions):

	Operating	Finance	Total
2022	$ 3	$ 3	$ 6
2023	2	2	4
2024	1	2	3
2025	1	2	3
2026	1	2	3
Thereafter	6	10	16
Total undiscounted lease payments	14	21	35
Less - amounts representing interest	(3)	(9)	(12)
Lease liabilities	$ 11	$ 12	$ 23

(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	2021	2020
Employee benefit plans[1]	17 years	$ 286	$ 432
Utah mine disposition[2]	Various	116	117
Unamortized contract values	2 years	36	42
Deferred net power costs	2 years	151	78
Unrealized loss on derivative contracts	N/A	—	17
Environmental costs	28 years	108	89
Asset retirement obligation	29 years	241	252
Demand side management (DSM)[3]	10 years	211	196
Other	Various	203	172
Total regulatory assets		$ 1,352	$ 1,395
Reflected as:			
Current assets		$ 65	$ 116
Noncurrent assets		1,287	1,279
Total regulatory assets		$ 1,352	$ 1,395

(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.

(3) In accordance with the Utah general rate case order issued in December 2020, $185 million of amounts billed to Utah customers under the Utah STEP program were used to accelerate depreciation of certain coal-fueled generation units as discussed in Note 3.

PacifiCorp had regulatory assets not earning a return on investment of $723 million and $707 million as of December 31, 2021 and 2020, 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	2021	2020
Cost of removal(1)	26 years	$ 1,187	$ 1,125
Deferred income taxes(2)	Various	1,307	1,463
Unrealized gain on regulated derivatives	1 year	53	—
Other	Various	221	254
Total regulatory liabilities		$ 2,768	$ 2,842
Reflected as:			
Current liabilities		$ 118	$ 115
Noncurrent liabilities		2,650	2,727
Total regulatory liabilities		$ 2,768	$ 2,842

(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, 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

The following table summarizes PacifiCorp's availability under its credit facilities as of December 31 (in millions):

2021:	
Credit facilities	$ 1,200
Less:	
Short-term debt	—
Tax-exempt bond support	(218)
Net credit facilities	$ 982
2020:	
Credit facilities	$ 1,200
Less:	
Short-term debt	(93)
Tax-exempt bond support	(218)
Net credit facilities	$ 889

As of December 31, 2021, PacifiCorp was in compliance with the covenants of its credit facilities and letter of credit arrangements.

PacifiCorp has a $1.2 billion unsecured credit facility expiring in June 2024 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 Eurodollar 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. As of December 31, 2021, PacifiCorp did not have any commercial paper borrowings outstanding. As of December 31, 2020, PacifiCorp had $93 million of commercial paper outstanding with a weighted average interest rate of 0.16%.

The credit facility requires 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, 2021 and 2020, PacifiCorp had $19 million and $11 million, respectively, of fully available letters of credit issued under committed arrangements in support of certain transactions required by third parties and 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

PacifiCorp's long-term debt was as follows as of December 31 (dollars in millions):

	2021			2020	
	Principal Amount	Carrying Value	Average Interest Rate	Carrying Value	Average Interest Rate
First mortgage bonds:					
2.95% to 8.53%, due through 2026	$ 1,379	$ 1,378	4.52 %	$ 2,245	4.12 %
2.70% to 7.70%, due 2027 to 2031	1,100	1,094	4.35	1,094	4.35
5.25% to 6.10%, due 2032 to 2036	850	845	5.75	845	5.75
5.75% to 6.35%, due 2037 to 2041	2,150	2,137	6.05	2,137	6.05
4.10% due 2042	300	297	4.10	297	4.10
2.90% to 4.15%, due 2049 to 2052	2,800	2,761	3.52	1,776	3.86
Variable-rate series, tax-exempt bond obligations (2021-0.12% to 0.13%; 2020-0.14% to 0.16%):					
Due 2025	25	25	0.12	25	0.14
Due 2024 to 2025[1]	193	193	0.13	193	0.15
Total long-term debt	$ 8,797	$ 8,730		$ 8,612	

Reflected as:

	2021	2020
Current portion of long-term debt	$ 155	$ 420
Long-term debt	8,575	8,192
Total long-term debt	$ 8,730	$ 8,612

(1) Secured by pledged first mortgage bonds registered to and held by the tax-exempt bond trustee generally with the same interest rates, maturity dates and redemption provisions as the tax-exempt bond obligations.

PacifiCorp's long-term debt generally includes provisions that allow PacifiCorp to redeem the first mortgage bonds in whole or in part at any time through the payment of a make-whole premium. Variable-rate tax-exempt bond obligations are generally redeemable at par value.

PacifiCorp currently has regulatory authority from the Oregon Public Utility Commission and the Idaho Public Utilities Commission to issue an additional $2.0 billion of long-term debt. PacifiCorp must make a notice filing with the Washington Utilities and Transportation Commission prior to any future issuance. PacifiCorp currently has an effective shelf registration statement filed with the United States Securities and Exchange Commission to issue an indeterminate amount of first mortgage bonds through September 2023.

The issuance of PacifiCorp's first mortgage bonds is limited by available property, earnings tests and other provisions of PacifiCorp's mortgage. Approximately $31 billion of PacifiCorp's eligible property (based on original cost) was subject to the lien of the mortgage as of December 31, 2021.

In November 2021, PacifiCorp exercised its par call redemption option, available in the final three months prior to scheduled maturity, and redeemed $450 million of its 2.95% Series First Mortgage Bonds that was originally due February 2022.

As of December 31, 2021, the annual principal maturities of long-term debt for 2022 and thereafter are as follows (in millions):

	Long-term Debt
2022	$ 155
2023	449
2024	591
2025	302
2026	100
Thereafter	7,200
Total	8,797
Unamortized discount and debt issuance costs	(67)
Total	$ 8,730

(9) Income Taxes

Income tax (benefit) expense consists of the following for the years ended December 31 (in millions):

	2021	2020	2019
Current:			
Federal	$ (150)	$ 19	$ 158
State	7	30	34
Total	(143)	49	192
Deferred:			
Federal	26	(124)	(132)
State	40	1	4
Total	66	(123)	(128)
Investment tax credits	(2)	(1)	(3)
Total income tax (benefit) expense	$ (79)	$ (75)	$ 61

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:

	2021	2020	2019
Federal statutory income tax rate	21 %	21 %	21 %
State income taxes, net of federal income tax benefit	3	3	3
Effects of ratemaking	(14)	(22)	(13)
Federal income tax credits	(20)	(13)	(3)
Other	—	—	(1)
Effective income tax rate	(10)%	(11)%	7 %

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.

Effects of ratemaking is primarily attributable to activity associated with excess deferred income taxes. Excess deferred income tax amortization, net of deferrals, was $112 million for 2021, including the use of $4 million to amortize certain regulatory asset balances in Wyoming and Idaho. Excess deferred income tax amortization, net of deferrals, was $132 million for 2020, including the use of $118 million to accelerate depreciation of certain retired equipment and to amortize certain regulatory balances in Idaho, Oregon and Utah. Excess deferred income taxes amortization, net of deferrals, was $93 million for 2019, including the use of $91 million to accelerate depreciation of certain retired wind equipment for Oregon.

The net deferred income tax liability consists of the following as of December 31 (in millions):

	2021	2020
Deferred income tax assets:		
Regulatory liabilities	$ 682	$ 700
Employee benefits	68	93
State carryforwards	73	73
Loss contingencies	63	63
Asset retirement obligations	73	65
Other	73	83
	1,032	1,077
Deferred income tax liabilities:		
Property, plant and equipment	(3,468)	(3,311)
Regulatory assets	(332)	(343)
Other	(79)	(50)
	(3,879)	(3,704)
Net deferred income tax liability	$ (2,847)	$ (2,627)

The following table provides PacifiCorp's net operating loss and tax credit carryforwards and expiration dates as of December 31, 2021 (in millions):

	State
Net operating loss carryforwards	$ 1,138
Deferred income taxes on net operating loss carryforwards	$ 53
Expiration dates	2023 - 2032
Tax credit carryforwards	$ 20
Expiration dates	2022 - indefinite

The United States 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 state income tax returns have expired through December 31, 2011, with the exception of Idaho, where the statute has expired through December 31, 2017, for all adjustments other than federal audit adjustments. The statute of limitations expiring 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, collectively 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 2021 as a result of the amount of lump sum distributions in the Retirement Plan during 2021 exceeding the service and interest cost threshold. This resulted in 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 the year ended December 31, 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		
	2021	2020	2019	2021	2020	2019
Service cost	$ —	$ —	$ —	$ 2	$ 2	$ 2
Interest cost	29	36	44	7	9	12
Expected return on plan assets	(51)	(56)	(67)	(9)	(14)	(21)
Settlement	6	—	—	—	—	—
Net amortization	21	18	11	1	3	—
Net periodic benefit cost (credit)	$ 5	$ (2)	$ (12)	$ 1	$ —	$ (7)

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	
	2021	2020	2021	2020
Plan assets at fair value, beginning of year	$ 1,064	$ 1,036	$ 327	$ 334
Employer contributions(1)	5	5	1	—
Participant contributions	—	—	6	4
Actual return on plan assets	109	124	14	15
Settlement(2)	(52)	—	—	—
Benefits paid	(68)	(101)	(24)	(26)
Plan assets at fair value, end of year	$ 1,058	$ 1,064	$ 324	$ 327

(1) 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	
	2021	2020	2021	2020
Benefit obligation, beginning of year	$ 1,202	$ 1,167	$ 307	$ 304
Service cost	—	—	2	2
Interest cost	29	36	7	9
Participant contributions	—	—	6	4
Actuarial (gain) loss	(63)	100	(10)	14
Settlement(1)	(52)	—	—	—
Benefits paid	(68)	(101)	(24)	(26)
Benefit obligation, end of year	$ 1,048	$ 1,202	$ 288	$ 307
Accumulated benefit obligation, end of year	$ 1,048	$ 1,202		

(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	
	2021	2020	2021	2020
Plan assets at fair value, end of year	$ 1,058	$ 1,064	$ 324	$ 327
Less - Benefit obligation, end of year	1,048	1,202	288	307
Funded status	$ 10	$ (138)	$ 36	$ 20
Amounts recognized on the Consolidated Balance Sheets:				
Other assets	$ 63	$ 8	$ 36	$ 20
Accrued employee expenses	(4)	(4)	—	—
Other long-term liabilities	(49)	(142)	—	—
Amounts recognized	$ 10	$ (138)	$ 36	$ 20

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 $69 million and $61 million as of December 31, 2021 and 2020, 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, 2021 and 2020, respectively, on the Consolidated Balance Sheets.

As of December 31, 2021, 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	
	2021	2020	2021	2020
Net loss (gain)	$ 298	$ 455	$ (28)	$ (13)
Regulatory deferrals[1]	11	2	2	3
Total	$ 309	$ 457	$ (26)	$ (10)

(1) Includes $9 million of deferrals associated with 2021 pension settlement losses.

A reconciliation of the amounts not yet recognized as components of net periodic benefit cost for the years ended December 31, 2021 and 2020 is as follows (in millions):

	Regulatory Asset	Accumulated Other Comprehensive Loss	Total
Pension			
Balance, December 31, 2019	$ 422	$ 21	$ 443
Net loss arising during the year	27	5	32
Net amortization	(17)	(1)	(18)
Total	10	4	14
Balance, December 31, 2020	432	25	457
Net gain arising during the year	(120)	(1)	(121)
Net amortization	(20)	(1)	(21)
Settlement	(6)	—	(6)
Total	(146)	(2)	(148)
Balance, December 31, 2021	$ 286	$ 23	$ 309

	Regulatory Liability
Other Postretirement	
Balance, December 31, 2019	$ (20)
Net loss arising during the year	13
Net amortization	(3)
Total	10
Balance, December 31, 2020	(10)
Net gain arising during the year	(15)
Net amortization	(1)
Total	(16)
Balance, December 31, 2021	$ (26)

Plan Assumptions

Assumptions used to determine benefit obligations and net periodic benefit cost were as follows:

	Pension			Other Postretirement		
	2021	**2020**	**2019**	**2021**	**2020**	**2019**
Benefit obligations as of December 31:						
Discount rate	2.90 %	2.50 %	3.25 %	2.90 %	2.50 %	3.20 %
Rate of compensation increase	N/A	N/A	N/A	N/A	N/A	N/A
Interest crediting rates for cash balance plan - non-union						
2019	N/A	N/A	3.40 %	N/A	N/A	N/A
2020	N/A	2.27 %	2.27 %	N/A	N/A	N/A
2021	0.82 %	0.82 %	2.27 %	N/A	N/A	N/A
2022	0.88 %	0.82 %	2.10 %	N/A	N/A	N/A
2023	0.88 %	2.00 %	2.10 %	N/A	N/A	N/A
2024 and beyond	1.90 %	2.00 %	2.10 %	N/A	N/A	N/A
Interest crediting rates for cash balance plan - union						
2019	N/A	N/A	3.15 %	N/A	N/A	N/A
2020	N/A	2.16 %	2.16 %	N/A	N/A	N/A
2021	1.42 %	1.42 %	2.16 %	N/A	N/A	N/A
2022	1.94 %	1.42 %	2.70 %	N/A	N/A	N/A
2023	1.94 %	2.40 %	2.70 %	N/A	N/A	N/A
2024 and beyond	2.30 %	2.40 %	2.70 %	N/A	N/A	N/A
Net periodic benefit cost for the years ended December 31:						
Discount rate	2.50 %	3.25 %	4.25 %	2.50 %	3.20 %	4.25 %
Expected return on plan assets	6.00	6.50	7.00	2.90	4.92	6.86

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 2022. 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 2022 through 2026 and for the five years thereafter are summarized below (in millions):

	Projected Benefit Payments	
	Pension	**Other Postretirement**
2022	$ 96	$ 24
2023	85	23
2024	79	22
2025	76	21
2026	71	20
2027-2031	304	87

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 advisors to manage 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, 2021:

	Pension(1)	**Other Postretirement**(1)
	%	%
Debt securities(2)	55 - 85	70 - 80
Equity securities(2)	25- 35	20 - 30
Other	0 - 10	0 - 1

(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, 2021:				
Cash equivalents	$ —	$ 15	$ —	$ 15
Debt securities:				
United States government obligations	51	—	—	51
Corporate obligations	—	299	—	299
Municipal obligations	—	22	—	22
Agency, asset and mortgage-backed obligations	—	38	—	38
Equity securities:				
United States companies	61	—	—	61
Total assets in the fair value hierarchy	$ 112	$ 374	$ —	$ 486
Investment funds[(2)] measured at net asset value				538
Limited partnership interests[(3)] measured at net asset value				34
Investments at fair value				$ 1,058
As of December 31, 2020:				
Cash equivalents	$ —	$ 32	$ —	$ 32
Debt securities:				
United States government obligations	14	—	—	14
International government obligations	—	—	—	—
Corporate obligations	—	231	—	231
Municipal obligations	—	21	—	21
Equity securities:				
United States companies	91	—	—	91
Total assets in the fair value hierarchy	$ 105	$ 284	$ —	$ 389
Investment funds[(2)] measured at net asset value				587
Limited partnership interests[(3)] measured at net asset value				88
Investments at fair value				$ 1,064

(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 59% and 41%, respectively, for 2021 and 78% and 22%, respectively, for 2020, and are invested in United States and international securities of approximately 84% and 16%, respectively, for 2021 and 74% and 26%, respectively, for 2020.

(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, 2021:				
Cash and cash equivalents	$ 4	$ 1	$ —	$ 5
Debt securities:				
United States government obligations	24	—	—	24
Corporate obligations	—	79	—	79
Municipal obligations	—	15	—	15
Agency, asset and mortgage-backed obligations	—	35	—	35
Equity securities:				
United States companies	4	—	—	4
Total assets in the fair value hierarchy	$ 32	$ 130	$ —	162
Investment funds[(2)] measured at net asset value				161
Limited partnership interests[(3)] measured at net asset value				1
Investments at fair value				$ 324
As of December 31, 2020:				
Cash and cash equivalents	$ 8	$ 1	$ —	$ 9
Debt securities:				
United States government obligations	11	—	—	11
Corporate obligations	—	86	—	86
Municipal obligations	—	16	—	16
Agency, asset and mortgage-backed obligations	—	44	—	44
Equity securities:				
United States companies	4	—	—	4
Total assets in the fair value hierarchy	$ 23	$ 147	$ —	170
Investment funds[(2)] measured at net asset value				153
Limited partnership interests[(3)] measured at net asset value				4
Investments at fair value				$ 327

(1) Refer to Note 13 for additional discussion regarding the three levels of the fair value hierarchy.

(2) Investment funds are substantially comprised of mutual funds and collective trust funds. These funds consist of equity and debt securities of approximately 39% and 61%, respectively, for 2021 and 38% and 62%, respectively, for 2020, and are invested in United States and international securities of approximately 90% and 10%, respectively, for 2021 and 93% and 7%, respectively, for 2020.

(3) Limited partnership interests include several funds that invest primarily in real estate, buyout, growth equity and venture capital.

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. 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 negotiations with the plan trustees.

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. This occurred as a result of Energy West Mining Company's withdrawal from the UMWA 1974 Pension 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[1]			
Plan name	**Employer Identification Number**	**2021**	**2020**	**2019**	**Funding improvement plan**	**Surcharge imposed under PPA of 2006[1]**	**2021**	**2020**	**2019**	**Year contributions to plan exceeded more than 5% of total contributions[2]**
Local 57 Trust Fund	87-0640888	At least 80%	At least 80%	At least 80%	None	None	$ 6	$ 6	$ 7	2019, 2018, 2017

(1) PacifiCorp's minimum contributions to the plan 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.

(2) For the Local 57 Trust Fund, information is for plan years beginning July 1, 2019, 2018 and 2017. Information for the plan year beginning July 1, 2020 is not yet available.

The current collective bargaining agreements governing the Local 57 Trust Fund expire in 2023.

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, 2021, 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 $40 million, $41 million and $40 million for the years ended December 31, 2021, 2020 and 2019, 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 $1,187 million and $1,125 million as of December 31, 2021 and 2020, respectively.

The following table reconciles the beginning and ending balances of PacifiCorp's ARO liabilities for the years ended December 31 (in millions):

	2021	2020
Beginning balance	$ 270	$ 257
Change in estimated costs	40	(11)
Additions	—	25
Retirements	(15)	(10)
Accretion	9	9
Ending balance	$ 304	$ 270
Reflected as:		
Other current liabilities	$ 5	$ 13
Other long-term liabilities	299	257
	$ 304	$ 270

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 may from time to time 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, 2021:					
Not designated as hedging contracts[1]:					
Commodity assets	$ 81	$ 21	$ 2	$ —	$ 104
Commodity liabilities	(5)	(1)	(38)	(7)	(51)
Total	76	20	(36)	(7)	53
Total derivatives	76	20	(36)	(7)	53
Cash collateral receivable	—	—	5	—	5
Total derivatives - net basis	$ 76	$ 20	$ (31)	$ (7)	$ 58
As of December 31, 2020:					
Not designated as hedging contracts[1]:					
Commodity assets	$ 29	$ 6	$ 1	$ —	$ 36
Commodity liabilities	(2)	—	(23)	(28)	(53)
Total	27	6	(22)	(28)	(17)
Total derivatives	27	6	(22)	(28)	(17)
Cash collateral receivable	—	—	15	9	24
Total derivatives - net basis	$ 27	$ 6	$ (7)	$ (19)	$ 7

(1) PacifiCorp's commodity derivatives are generally included in rates. As of December 31, 2021 a regulatory liability of $53 million was recorded related to the net derivative asset of $53 million. As of December 31, 2020 regulatory asset of $17 million was recorded related to the net derivative liability of $17 million.

The following table reconciles the beginning and ending balances of PacifiCorp's net regulatory assets and summarizes the pre-tax gains and losses on commodity derivative contracts recognized in net regulatory assets, as well as amounts reclassified to earnings for the years ended December 31 (in millions):

	2021	2020	2019
Beginning balance	$ 17	$ 62	$ 96
Changes in fair value recognized in regulatory assets	(171)	(11)	(37)
Net (losses) gains reclassified to operating revenue	(23)	3	(34)
Net gains (losses) reclassified to energy costs	124	(37)	37
Ending balance	$ (53)	$ 17	$ 62

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	2021	2020
Electricity purchases (sales), net	Megawatt hours	2	(1)
Natural gas purchases	Decatherms	106	100

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 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 PacifiCorp's creditworthiness. These rights can vary by contract and by counterparty. As of December 31, 2021, PacifiCorp'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 PacifiCorp's derivative contracts in liability positions with specific credit-risk-related contingent features totaled $37 million and $51 million as of December 31, 2021 and 2020, respectively, for which PacifiCorp had posted collateral of $5 million and $24 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, 2021 and 2020, PacifiCorp would have been required to post $23 million and $25 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, 2021:					
Assets:					
Commodity derivatives	$ —	$ 104	$ —	$ (8)	$ 96
Money market mutual funds	181	—	—	—	181
Investment funds	27	—	—	—	27
	$ 208	$ 104	$ —	$ (8)	$ 304
Liabilities - Commodity derivatives	$ —	$ (51)	$ —	$ 13	$ (38)
As of December 31, 2020:					
Assets:					
Commodity derivatives	$ —	$ 36	$ —	$ (3)	$ 33
Money market mutual funds	6	—	—	—	6
Investment funds	25	—	—	—	25
	$ 31	$ 36	$ —	$ (3)	$ 64
Liabilities - Commodity derivatives	$ —	$ (53)	$ —	$ 27	$ (26)

(1) Represents netting under master netting arrangements and a net cash collateral receivable of $5 million and $24 million as of December 31, 2021 and 2020, 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 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):

	2021		2020	
	Carrying Value	**Fair Value**	**Carrying Value**	**Fair Value**
Long-term debt	$ 8,730	$ 10,374	$ 8,612	$ 10,995

(14) Commitments and Contingencies

Legal Matters

PacifiCorp is party to a variety of legal actions arising out of the normal course of business. Plaintiffs occasionally seek punitive or exemplary damages. PacifiCorp does not believe that such normal and routine litigation will have a material impact on its consolidated financial results. PacifiCorp 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 and are described below.

California and Oregon 2020 Wildfires

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 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. Fire suppression costs estimated by various agencies total approximately $150 million. Investigations into the cause and origin of each wildfire are complex and ongoing and being conducted by various entities, including the United States Forest Service, the California Public Utilities Commission, the Oregon Department of Forestry, the Oregon Department of Justice, PacifiCorp and various experts engaged by PacifiCorp.

Several lawsuits have been filed in Oregon and California, including a putative class action complaint in Oregon, on behalf of citizens and businesses who suffered damages from fires allegedly caused by PacifiCorp. Additionally, multiple insurance carriers have filed subrogation complaints in Oregon and California with allegations similar to those made in the aforementioned lawsuits. The final determinations of liability, however, will only be made following comprehensive investigations and litigation processes.

In California, under inverse condemnation, courts have held that investor-owned utilities can be liable for real and personal property damages 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 nevertheless be found liable for all damages proximately caused by negligence, including property and natural resource damage; fire suppression costs; personal injury and loss of life damages; and interest.

PacifiCorp has accrued $136 million as its best estimate of the potential losses net of expected insurance recoveries associated with the 2020 Wildfires that are considered probable of being incurred. These accruals include estimated losses for fire suppression costs, property damage, personal injury damages and loss of life damages. It is reasonably possible that PacifiCorp will incur additional losses beyond the amounts accrued; however, PacifiCorp is currently unable to estimate the range of possible additional losses that could be incurred due to the number of properties and parties involved and the lack of specific claims for all potential claimants. To the extent losses beyond the amounts accrued are incurred, additional insurance coverage is expected to be available to cover at least a portion of the losses.

Environmental Laws and Regulations

PacifiCorp is subject to federal, state and local laws and regulations regarding air and water quality, renewable portfolio standards, emissions performance standards, climate change, coal combustion byproduct disposal, hazardous and solid waste disposal, protected species and other environmental matters that have the potential to impact PacifiCorp's current and future operations. PacifiCorp believes it is in material compliance with all applicable laws and regulations.

Hydroelectric Relicensing

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 dams from PacifiCorp to the KRRC. The FERC approved 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 Klamath Hydroelectric 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 transfer of the four mainstem Klamath 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. The transfer will be effective within 30 days following the issuance of a license surrender from the FERC for the project, which remains pending.

As of December 31, 2021, PacifiCorp's assets included $14 million of costs associated with the Klamath hydroelectric system's mainstem dams and the associated relicensing and settlement costs, which are being depreciated and amortized in accordance with state regulatory approvals in Utah, Wyoming and Idaho through December 31, 2022.

Hydroelectric Commitments

Certain of PacifiCorp's hydroelectric licenses contain requirements for PacifiCorp to make certain capital and operating expenditures related to its hydroelectric facilities, which are estimated to be approximately $193 million over the next 10 years. Included in these estimates are commitments associated with the KHSA.

Commitments

PacifiCorp has the following firm commitments that are not reflected on the Consolidated Balance Sheet. Minimum payments as of December 31, 2021 are as follows (in millions):

	2022	2023	2024	2025	2026	2027 and Thereafter	Total
Contract type:							
Purchased electricity contracts - commercially operable	$ 372	$ 223	$ 212	$ 194	$ 192	$ 2,190	$ 3,383
Fuel contracts	586	366	310	134	129	468	1,993
Construction commitments	51	106	27	—	—	—	184
Transmission	108	106	90	62	51	431	848
Easements	20	20	19	19	19	518	615
Maintenance, service and other contracts	113	56	53	52	51	253	578
Total commitments	$ 1,250	$ 877	$ 711	$ 461	$ 442	$ 3,860	$ 7,601

Purchased Electricity Contracts - Commercially Operable

As part of its energy resource portfolio, PacifiCorp acquires a portion of its electricity through long-term purchases and exchange agreements. PacifiCorp has several PPAs with solar-powered or wind-powered 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. 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 2021, 2020 and 2019 energy sources.

Fuel Contracts

PacifiCorp has "take or pay" coal and natural gas contracts that require minimum payments.

Construction Commitments

PacifiCorp's construction commitments included in the table above relate to firm commitments and include costs associated with certain generating plant, transmission, and distribution projects.

Transmission

PacifiCorp has contracts for the right to transmit electricity over other entities' transmission lines to facilitate delivery to PacifiCorp's customers.

Easements

PacifiCorp has non-cancelable easements for land on which certain of its assets, primarily wind-powered generating facilities, are located.

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):

	2021	2020	2019
Customer Revenue:			
Retail:			
Residential	$ 1,914	$ 1,910	$ 1,783
Commercial	1,559	1,578	1,522
Industrial	1,125	1,185	1,176
Other retail	249	259	230
Total retail	4,847	4,932	4,711
Wholesale	157	107	99
Transmission	143	96	98
Other Customer Revenue	108	108	78
Total Customer Revenue	5,255	5,243	4,986
Other revenue	41	98	82
Total operating revenue	$ 5,296	$ 5,341	$ 5,068

(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, 2021 and 2020. 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, 2021 and 2020.

(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, 2021, 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, 2021, PacifiCorp's actual common equity percentage, as calculated under this measure, was 54%, and PacifiCorp would have been permitted to dividend $3.2 billion under this commitment.

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, 2021, PacifiCorp met the minimum required senior unsecured debt ratings for making distributions.

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 $17 million and $19 million as of December 31, 2021 and 2020, 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 remaining 33.33% of the coal produced is purchased by the joint venture partner. 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 $45 million and $74 million as of December 31, 2021 and 2020, respectively. Refer to Note 21 for information regarding related party transactions with Bridger Coal.

(20) Supplemental Cash Flow Disclosures

Cash and Cash Equivalents and Restricted Cash and Cash Equivalents

A reconciliation of cash and cash equivalents and restricted cash and cash equivalents as of December 31, 2021 and 2020, as presented in 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):

	2021	2020
Cash and cash equivalents	$ 179	$ 13
Restricted cash included in other current assets	4	4
Restricted cash included in other assets	3	2
Total cash and cash equivalents and restricted cash and cash equivalents	$ 186	$ 19

The summary of supplemental cash flow disclosures as of and for the years ended December 31 is as follows (in millions):

	2021	2020	2019
Supplemental disclosure of cash flow information:			
Interest paid, net of amounts capitalized	$ 395	$ 348	$ 340
Income taxes (received) paid, net	$ (120)	$ 107	$ 171
Supplemental disclosure of non-cash investing and financing activities:			
Accounts payable related to property, plant and equipment additions	$ 254	$ 344	$ 293

(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 this agreement totaled $18 million, $10 million and $10 million during the years ended December 31, 2021, 2020 and 2019, respectively. Payables associated with these services were $9 million and $5 million as of December 31, 2021 and 2020, respectively. Amounts charged by PacifiCorp to BHE and its subsidiaries under this agreement totaled $8 million, $4 million and $1 million during the years ended December 31, 2021, 2020 and 2019, respectively.

In 2021, PacifiCorp sold wind turbines previously acquired from a third party to BHE Wind, LLC, an indirect wholly owned subsidiary of BHE, for $6 million. In 2020, PacifiCorp acquired wind turbines from BHE Wind, LLC for $147 million. The wind turbines were installed as part of newly constructed and repowered wind-powered generating facilities.

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, $6 million and $7 million during the years ended December 31, 2021, 2020 and 2019, 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 $19 million, $29 million and $35 million during the years ended December 31, 2021, 2020 and 2019, respectively.

PacifiCorp is party to a tax-sharing agreement and is part of the Berkshire Hathaway consolidated United States federal income tax return. Federal and state income taxes receivable from BHE were $48 million and $25 million as of December 31, 2021 and 2020, respectively. For the year ended December 31, 2021, cash refunded from BHE for federal and state income taxes totaled $120 million. For the years ended December 31, 2020 and 2019, cash paid to BHE for federal and state income taxes totaled $107 million and $171 million, respectively.

PacifiCorp transacts with its equity investees, Bridger Coal and Trapper Mining Inc. Services provided by equity investees to PacifiCorp primarily relate to coal purchases. During the years ended December 31, 2021, 2020 and 2019, coal purchases from PacifiCorp's equity investees totaled $148 million, $145 million and $155 million, respectively. Payables to PacifiCorp's equity investees were $7 million and $14 million as of December 31, 2021 and 2020, 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

<u>Overview</u>

MidAmerican Energy -

MidAmerican Energy's net income for 2021 was $894 million, an increase of $68 million, or 8%, compared to 2020 primarily due to higher electric utility margin of $190 million and a favorable income tax benefit of $105 million, partially offset by higher depreciation and amortization expense of $198 million, higher operations and maintenance expense of $21 million and lower allowances for equity and borrowed funds of $8 million. Electric utility margin increased primarily due to a higher retail utility margin of $99 million, largely from higher volumes of 5.8% and price impacts from changes in sales mix, and higher wholesale utility margin of $93 million from higher margins per unit and higher volumes of 42.7%. Operations and maintenance expense increased primarily due to higher costs associated with additional wind-powered generating facilities placed in-service as well as higher natural gas distribution costs, partially offset by 2020 costs associated with storm restoration activities. The increase in depreciation and amortization expense was primarily due to higher regulatory mechanisms of $139 million and additional assets placed in-service. The favorable income tax benefit was from higher PTCs recognized of $64 million due to new wind-powered generating facilities placed in-service in late 2020 and 2021, state income tax impacts and lower pretax income.

MidAmerican Energy's net income for 2020 was $826 million, an increase of $33 million, or 4%, compared to 2019 primarily due to a higher income tax benefit of $199 million from higher PTCs recognized of $132 million, lower pretax income of $166 million and the effects of ratemaking, and lower operations and maintenance expenses, partially offset by higher depreciation and amortization expense of $77 million, lower allowances for equity and borrowed funds used during construction of $45 million, higher interest expense of $23 million and lower electric and natural gas utility margins. Higher PTCs recognized were due to greater wind-powered generation driven primarily by repowering and new wind projects placed in-service in 2019. Depreciation and amortization expense increased due to additional assets placed in-service in 2019 and 2020, partially offset by $23 million of lower Iowa revenue sharing accruals. Electric utility margin decreased due to a lower wholesale utility margin, reflecting lower margins per unit, net of higher wholesale volumes, partially offset by a higher retail utility margin from higher volumes. Electric retail customer volumes increased 1.2% due to increased usage for certain industrial customers, partially offset by the impacts of COVID-19, which resulted in lower commercial and industrial customer usage and higher residential customer usage. Natural gas utility margin decreased primarily due to 10.2% lower retail customer volumes mainly from the unfavorable impact of weather.

MidAmerican Funding -

MidAmerican Funding's net income for 2021 was $883 million, an increase of $65 million, or 8%, compared to 2020. MidAmerican Funding's net income for 2020 was $818 million, an increase of $37 million, or 5%, compared to 2019. The increases were primarily due to the changes in MidAmerican Energy's earnings discussed above.

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):

	2021	2020	Change		2020	2019	Change	
Electric utility margin:								
Operating revenue	$ 2,529	$ 2,139	$ 390	18 %	$ 2,139	$ 2,237	$ (98)	(4)%
Cost of fuel and energy	539	339	200	59	339	399	(60)	(15)
Electric utility margin	1,990	1,800	190	11 %	1,800	1,838	(38)	(2)%
Natural gas utility margin:								
Operating revenue	1,003	573	430	75 %	573	660	(87)	(13)%
Natural gas purchased for resale	760	327	433	*	327	395	(68)	(17)
Natural gas utility margin	243	246	(3)	(1)%	246	265	(19)	(7)%
Utility margin	$ 2,233	$ 2,046	$ 187	9 %	$ 2,046	$ 2,103	$ (57)	(3)%
Other operating revenue	15	8	7	88 %	8	28	(20)	(71)%
Other cost of sales	1	1	—	—	1	18	(17)	(94)
Operations and maintenance	775	754	21	3	754	800	(46)	(6)
Depreciation and amortization	914	716	198	28	716	639	77	12
Property and other taxes	142	135	7	5	135	126	9	7
Operating income	$ 416	$ 448	$ (32)	(7)%	$ 448	$ 548	$ (100)	(18)%

* 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:

	2021	2020	Change		2020	2019	Change	
Utility margin (in millions):								
Operating revenue	$ 2,529	$ 2,139	$ 390	18 %	$ 2,139	$ 2,237	$ (98)	(4)%
Cost of fuel and energy	539	339	200	59	339	399	(60)	(15)
Utility margin	$ 1,990	$ 1,800	$ 190	11 %	$ 1,800	$ 1,838	$ (38)	(2)%
Sales (GWhs):								
Residential	6,718	6,687	31	— %	6,687	6,575	112	2 %
Commercial	3,841	3,707	134	4	3,707	3,921	(214)	(5)
Industrial	15,944	14,645	1,299	9	14,645	14,127	518	4
Other	1,571	1,484	87	6	1,484	1,578	(94)	(6)
Total retail	28,074	26,523	1,551	6	26,523	26,201	322	1
Wholesale	16,011	11,219	4,792	43	11,219	10,000	1,219	12
Total sales	44,085	37,742	6,343	17 %	37,742	36,201	1,541	4 %
Average number of retail customers (in thousands)	804	795	9	1 %	795	786	9	1 %
Average revenue per MWh:								
Retail	$ 75.84	$ 72.57	$ 3.27	5 %	$ 72.57	$ 74.01	$ (1.44)	(2)%
Wholesale	$ 18.92	$ 11.08	$ 7.84	71 %	$ 11.08	$ 21.84	$ (10.76)	(49)%
Heating degree days	5,704	5,932	(228)	(4)%	5,932	6,661	(729)	(11)%
Cooling degree days	1,331	1,172	159	14 %	1,172	1,152	20	2 %
Sources of energy (GWhs)[(1)]:								
Wind and other[(2)]	23,374	20,668	2,706	13 %	20,668	16,136	4,532	28 %
Coal	12,313	7,217	5,096	71	7,217	12,182	(4,965)	(41)
Nuclear	3,934	3,927	7	—	3,927	3,849	78	2
Natural gas	1,398	675	723	*	675	441	234	53
Total energy generated	41,019	32,487	8,532	26	32,487	32,608	(121)	—
Energy purchased	3,865	5,979	(2,114)	(35)	5,979	4,292	1,687	39
Total	44,884	38,466	6,418	17 %	38,466	36,900	1,566	4 %
Average cost of energy per MWh:								
Energy generated[(3)]	$ 7.12	$ 4.74	$ 2.38	50 %	$ 4.74	$ 7.53	$ (2.79)	(37)%
Energy purchased	$ 64.04	$ 30.94	$ 33.10	*	$ 30.94	$ 35.82	$ (4.88)	(14)%

* 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:

	2021	2020	Change		2020	2019	Change	
Utility margin (in millions):								
Operating revenue	$ 1,003	$ 573	$ 430	75 %	$ 573	$ 660	$ (87)	(13)%
Natural gas purchased for resale	760	327	433	*	327	395	(68)	(17)
Utility margin	$ 243	$ 246	$ (3)	(1)%	$ 246	$ 265	$ (19)	(7)%
Throughput (000's Dths):								
Residential	48,984	51,023	(2,039)	(4)%	51,023	56,101	(5,078)	(9)%
Commercial	23,240	23,336	(96)	—	23,336	27,333	(3,997)	(15)
Industrial	5,287	5,275	12	—	5,275	5,258	17	—
Other	68	74	(6)	(8)	74	77	(3)	(4)
Total retail sales	77,579	79,708	(2,129)	(3)	79,708	88,769	(9,061)	(10)
Wholesale sales	34,337	34,691	(354)	(1)	34,691	36,886	(2,195)	(6)
Total sales	111,916	114,399	(2,483)	(2)	114,399	125,655	(11,256)	(9)
Natural gas transportation service	112,631	110,263	2,368	2	110,263	112,143	(1,880)	(2)
Total throughput	224,547	224,662	(115)	— %	224,662	237,798	(13,136)	(6)%
Average number of retail customers (in thousands)	781	774	7	1 %	774	766	8	1 %
Average revenue per retail Dth sold	$ 10.59	$ 5.91	$ 4.68	79 %	$ 5.91	$ 6.03	$ (0.12)	(2)%
Heating degree days	6,000	6,253	(253)	(4)%	6,253	6,980	(727)	(10)%
Average cost of natural gas per retail Dth sold	$ 7.95	$ 3.29	$ 4.66	*	$ 3.29	$ 3.47	$ (0.18)	(5)%
Combined retail and wholesale average cost of natural gas per Dth sold	$ 6.79	$ 2.86	$ 3.93	*	$ 2.86	$ 3.14	$ (0.28)	(9)%

* Not meaningful.

Year Ended December 31, 2021 Compared to Year Ended December 31, 2020

MidAmerican Energy -

Electric utility margin increased $190 million, or 11%, for 2021 compared to 2020 primarily due to:

- a $99 million increase in retail utility margin primarily due to $50 million from higher usage for certain industrial customers; $13 million from the favorable impact of weather; $19 million due to price impacts from changes in sales mix; $10 million, net of energy costs, from higher recoveries through bill riders (offset in operations and maintenance expense and income tax benefit) and $6 million from liquidated damages related to a wind-powered generation project. Retail customer volumes increased 5.8%; and
- a $93 million increase in wholesale utility margin due to higher margins per unit of $52 million, reflecting higher market prices, net of higher energy costs, and higher volumes of 42.7%; partially offset by
- a $2 million decrease in Multi-Value Projects ("MVP") transmission revenue.

Natural gas utility margin decreased $3 million, or 1%, for 2021 compared to 2020 primarily due to:

- a $6 million decrease from higher refunds related to amortization of excess accumulated deferred income taxes arising from 2017 Tax Reform (offset in income tax benefit);
- a $3 million decrease due to the unfavorable impact of weather, partially offset by price impacts from changes in sales mix; partially offset by
- a $4 million increase in natural gas energy efficiency program revenue (offset in operations and maintenance expense); and
- a $2 million increase in natural gas transportation margin, reflecting higher volumes.

Operations and maintenance increased $21 million, or 3%, for 2021 compared to 2020 primarily due higher other generation operations and maintenance expenses of $7 million due to additional wind turbines and easements, higher energy efficiency program expense of $7 million (offset in operating revenue), higher natural gas distribution costs of $6 million and higher transmission operations costs from MISO of $3 million, partially offset by lower electric distribution costs of $11 million due to storm restoration costs in 2020.

Depreciation and amortization increased $198 million, or 28%, for 2021 compared to 2020 primarily due to $114 million from higher Iowa revenue sharing accruals, $25 million from a regulatory mechanism that provides customers the retail energy benefits of certain wind-powered generation projects and $59 million related to new and repowered wind-powered generating facilities and other plant placed in-service.

Property and other taxes increased $7 million, or 5%, for 2021 compared to 2020 primarily due to higher wind turbine property taxes.

Interest expense decreased $2 million, or 1%, for 2021 compared to 2020 primarily due to a decrease in a regulatory carrying charge and lower variable interest rates, partially offset by a higher average long-term debt balance.

Allowance for borrowed and equity funds decreased $8 million, or 13%, for 2021 compared to 2020 primarily due to lower construction work-in-progress balances related to wind-powered generation projects.

Other, net increased $1 million, or 2%, for 2021 compared to 2020 primarily due to higher cash surrender values of corporate-owned life insurance policies and lower non-service costs of postretirement employee benefit plans, partially offset by a gain from the contribution of land to a joint venture in 2020.

Income tax benefit increased $105 million, or 18%, for 2021 compared to 2020, and the effective tax rate was (308)% for 2021 and (223)% for 2020. The change in the effective tax rate was substantially due to an increase of $64 million in PTCs, state income tax impacts and lower pretax income in 2021.

Federal renewable electricity PTCs are earned as energy from qualifying wind-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-powered generation placed in-service. The full credit per kilowatt hour was $0.025 for 2019 through 2021. The full credit, or a portion thereof, was applied to the annual production of eligible facilities, which resulted in $574 million, $510 million and $378 million of PTCs in 2021, 2020 and 2019, respectively.

MidAmerican Funding -

Income tax benefit for MidAmerican Funding increased $106 million, or 18%, for 2021 compared to 2020, and the effective tax rate was (335)% for 2021 and (235)% for 2020. The change in effective tax rates was due principally to the factors discussed for MidAmerican Energy.

Year Ended December 31, 2020 Compared to Year Ended December 31, 2019

MidAmerican Energy -

Electric utility margin decreased $38 million, or 2%, for 2020 compared to 2019 primarily due to:

- a $60 million decrease in wholesale utility margin due to lower margins per unit of $78 million, reflecting lower market prices, partially offset by lower energy costs and higher volumes of 12.2%; partially offset by
- an $18 million increase in retail utility margin primarily due to an increase of $23 million from non-weather-related factors, net of price impacts from sales mix, including increased usage for certain industrial customers and the impacts of COVID-19, which generally resulted in lower commercial and industrial customer usage and higher residential customer usage; an increase of $1 million, net of energy costs, from higher recoveries through bill riders, primarily related to lower refunds related to the ratemaking treatment of 2017 Tax Reform (offset in income tax benefit) and higher transmission cost recoveries (offset in operations and maintenance expense), substantially offset by a decrease of $28 million in electric energy efficiency program revenue (offset in operations and maintenance expense) and the PTC component of the EAC (offset in income tax benefit); partially offset by a decrease of $3 million from the impact of weather. Retail customer volumes increased 1.2%; and
- a $4 million increase in MVP transmission revenue.

Natural gas utility margin decreased $19 million, or 7%, for 2020 compared to 2019 primarily due to:

- a decrease of $10 million in natural gas energy efficiency program revenue (offset in operations and maintenance expense); and
- a decrease of $9 million from the unfavorable impact of weather in the first quarter.

Operations and maintenance decreased $46 million, or 6%, for 2020 compared to 2019 primarily due to lower energy efficiency program expense of $38 million (offset in operating revenue), lower fossil-fueled generation maintenance of $14 million, lower natural gas distribution expenses of $10 million, lower electric distribution operations expenses of $7 million, a nuclear property insurance premium refund of $5 million and decreases in benefit plan service costs and healthcare and other administrative costs, partially offset by higher wind-powered generation expenses of $21 million due to new and repowered wind-powered generating facilities placed in-service in 2019 and easements, higher electric distribution maintenance expenses of $13 million largely driven by storm restoration related to a significant wind storm in August 2020 and higher transmission operations costs from MISO of $5 million (offset in operating revenue).

Depreciation and amortization increased $77 million, or 12%, for 2020 compared to 2019 primarily due to $95 million related to new and repowered wind-powered generating facilities and other plant placed in-service, partially offset by lower Iowa revenue sharing accruals of $23 million.

Property and other taxes increased $9 million, or 7%, for 2020 compared to 2019 due to higher wind turbine property taxes and other real estate taxes.

Interest expense increased $23 million, or 8%, for 2020 compared to 2019 primarily due to higher average long-term debt balances.

Allowance for borrowed and equity funds decreased $45 million, or 43%, for 2020 compared to 2019 primarily due to lower construction work-in-progress balances related to new and repowered wind-powered generation projects.

Other, net increased $2 million, or 4%, for 2020 compared to 2019 primarily due to lower non-service costs of postretirement employee benefit plans and a gain from the contribution of land to a joint venture in 2020, partially offset by lower interest income due to an unfavorable cash position and lower cash surrender values of corporate-owned life insurance policies.

Income tax benefit increased $199 million, or 54%, for 2020 compared to 2019, and the effective tax rate was (223)% for 2020 and (88)% for 2019. The change in the effective tax rate was substantially due to an increase of $132 million in PTCs, state income tax impacts, the effects of ratemaking and lower pretax income in 2020.

MidAmerican Funding -

Income tax benefit for MidAmerican Funding increased $197 million, or 52%, for 2020 compared to 2019, and the effective tax rate was (235)% for 2020 and (93)% for 2019. The change in effective tax rates was due principally to the factors discussed for MidAmerican Energy.

Liquidity and Capital Resources

As of December 31, 2021, MidAmerican Energy's and MidAmerican Funding's total net liquidity were as follows (in millions):

MidAmerican Energy:		
Cash and cash equivalents	$	232
Credit facilities, maturing 2022 and 2024		1,505
Less:		
Tax-exempt bond support		(370)
Net credit facilities		1,135
MidAmerican Energy total net liquidity	$	1,367
MidAmerican Funding:		
MidAmerican Energy total net liquidity	$	1,367
Cash and cash equivalents		1
MHC, Inc. credit facility, maturing 2022		4
MidAmerican Funding total net liquidity	$	1,372

Operating Activities

MidAmerican Energy's net cash flows from operating activities were $1,617 million, $1,543 million and $1,490 million for 2021, 2020 and 2019, respectively. MidAmerican Funding's net cash flows from operating activities were $1,605 million, $1,536 million and $1,475 million for 2021, 2020 and 2019, respectively. Cash flows from operating activities increased for 2021 compared to 2020 primarily due to higher income tax receipts, lower payments for the settlement of AROs and lower interest payments. Cash flows from operating activities increased for 2020 compared to 2019 primarily due to higher income tax receipts and lower payments to vendors, partially offset by higher payments for the settlement of AROs, lower utility margins for MidAmerican Energy's regulated electric and natural gas businesses and higher interest payments due to long-term debt issued in October 2019.

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.

In February 2021, severe cold weather over the central United States caused disruptions in natural gas supply from the southern part of the United States. These disruptions, combined with increased demand, resulted in historically high prices for natural gas purchased for resale to MidAmerican Energy's retail customers and caused an approximate $245 million increase in natural gas costs above those normally expected. To mitigate the impact to customers, the IUB ordered the recovery of these higher costs to be applied to customer bills over the period April 2021 through April 2022 based on a customer's monthly natural gas usage. While sufficient liquidity is available to MidAmerican Energy, the increased costs and longer recovery period resulted in higher working capital requirements during the year ended December 31, 2021.

Investing Activities

MidAmerican Energy's net cash flows from investing activities were $(1,911) million, $(1,826) million and $(2,801) million for 2021, 2020 and 2019, respectively. MidAmerican Funding's net cash flows from investing activities were $(1,912) million, $(1,825) million and $(2,801) million for 2021, 2020 and 2019, 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 investment proceeds relates primarily to company-owned life insurance policies.

Financing Activities

MidAmerican Energy's net cash flows from financing activities were $488 million, $(2) million and $1,585 million for 2021, 2020 and 2019, respectively. MidAmerican Funding's net cash flows from financing activities were $501 million, $4 million and $1,600 million for 2021, 2020 and 2019, respectively. In July 2021, MidAmerican Energy issued $500 million of its 2.70% First Mortgage Bonds due August 2052. In January 2019, MidAmerican Energy issued $600 million of its 3.65% First Mortgage Bonds due April 2029 and $900 million of its 4.25% First Mortgage Bonds due July 2049, and in October 2019, issued an additional $250 million of its 3.65% First Mortgage Bonds due April 2029 and $600 million of its 3.15% First Mortgage Bonds due April 2050. In February 2019, MidAmerican Energy redeemed $500 million of its 2.40% First Mortgage Bonds due in March 2019 at a redemption price of 100% of the principal amount plus accrued interest. Net (repayments of) proceeds from short-term debt relate to MidAmerican Energy's use of short-term borrowings through its commercial paper program. MidAmerican Funding received $12 million, $5 million and $15 million in 2021, 2020 and 2019, respectively, through its note payable with BHE.

Debt Authorizations and Related Matters

Short-term Debt

MidAmerican Energy has authority from the FERC to issue through April 2, 2022, commercial paper and bank notes aggregating $1.5 billion at interest rates not to exceed the applicable London Interbank Offered Rate plus a spread of 400 basis points. MidAmerican Energy has a $1.5 billion unsecured credit facility expiring in June 2024. 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 Eurodollar rate 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 for general corporate purposes.

Long-term Debt and Preferred Stock

MidAmerican Energy currently has an effective automatic registration statement with the SEC to issue an indeterminate amount of long-term debt securities and preferred stock through June 13, 2024. MidAmerican Energy has authorization from the FERC to issue, through June 30, 2023, long-term debt securities up to an aggregate of $2.0 billion and preferred stock up to an aggregate of $500 million and from the ICC to issue long-term debt securities up to an aggregate of $350 million through August 20, 2022. Additionally, MidAmerican Energy has authority from the ICC through October 15, 2024, to issue $750 million of long-term debt securities for the purpose of refinancing $250 million of its 3.70% Senior notes due September 2023 and $500 million of its 2.40% Senior notes due October 2024.

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, 2021, MidAmerican Energy estimated it would be able to issue up to $8.1 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		
	2019	**2020**	**2021**	**2022**	**2023**	**2024**
Wind generation	$ 1,877	$ 911	$ 964	$ 792	$ 1,810	$ 1,741
Electric distribution	277	273	257	274	238	155
Electric transmission	177	160	199	173	85	83
Solar generation	2	16	132	93	58	—
Other	477	476	360	581	459	332
Total	$ 2,810	$ 1,836	$ 1,912	$ 1,913	$ 2,650	$ 2,311

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 and acquisition of wind-powered generating facilities totaled $540 million for 2021, $848 million for 2020 and $1,486 million for 2019. MidAmerican Energy placed in-service 294 MWs during 2021, 729 MWs during 2020, including the acquisition of an existing 80-MW wind farm and 1,019 MWs during 2019. All of these wind-powered generating facilities placed in-service in 2021, 2020 and 2019 qualify for 100% of PTCs available. PTCs from these projects are excluded from MidAmerican Energy's Iowa EAC until these generation assets are reflected in base rates.
  - Repowering of wind-powered generating facilities totaled $354 million for 2021, $37 million for 2020 and $369 million for 2019. Planned spending for repowering totals $509 million in 2022. 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. The rate at which PTCs are re-established for a facility depends upon the date construction begins. Of the 865 MWs of current repowering projects not in-service as of December 31, 2021, 564 MWs are currently expected to qualify for 80% of the PTCs available for 10 years following each facility's return to service and 301 MWs are expected to qualify for 60% of such credits.
- 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 of solar-powered generating facilities totaling 141 MWs of small- and utility-scale solar generation, with total spend of $132 million in 2021 and planned spending of $93 million in 2022 and $58 million in 2023.

- 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 $5.6 billion on long-term debt, including $303 million due in 2022. Additionally, MidAmerican Funding has cash requirements relating to interest payments on its long-term debt of $124 million, including $17 million due in 2022.

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 Corp. ("Constellation Energy," previously Exelon Generation Company, LLC, which was a subsidiary of Exelon Corporation prior to February 1, 2022), the operator of Quad Cities Generating Station Units 1 and 2 ("Quad Cities Station") of which MidAmerican Energy has a 25% ownership interest, announced on June 2, 2016, its intention to shut down Quad Cities Station on June 1, 2018. 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. The proceeds from the ZECs will provide Constellation Energy additional revenue through 2027 as an incentive for continued operation of Quad Cities Station. MidAmerican Energy will 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, 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-fired resources. An expanded PJM MOPR to include existing resources would require exclusion of ZEC compensation when bidding into future capacity auctions, resulting in an increased risk of Quad Cities Station not receiving capacity revenues in future auctions.

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 in May 2021. While the FERC included some limited exemptions, no exemptions were available to state-supported nuclear resources, such as Quad Cities Station. The FERC provided no new mechanism for accommodating state-supported resources 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. In response to the FERC's order, the PJM submitted a compliance filing on March 18, 2020, wherein the PJM proposed tariff language reflecting the FERC's directives and a schedule for resuming capacity auctions. On April 16, 2020, the FERC issued an order largely denying requests for rehearing of the FERC's December 2019 order but granting a few clarifications that required an additional PJM compliance filing, which the PJM submitted on June 1, 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 D.C. Circuit.

As a result, the MOPR applied to Quad Cities Station in the capacity auction for the 2022-2023 planning year, 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 at 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 will no longer apply to Quad Cities Station. 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. Constellation Energy is strenuously opposing these appeals.

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's December 19, 2019 order on the PJM MOPR may undermine the continued effectiveness of the Illinois zero emission standard 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 climate change, RPS, air and water quality, emissions performance standards, coal combustion byproduct disposal, hazardous and solid waste disposal, protected species 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. All such laws and regulations are subject to a range of interpretation, which 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. MidAmerican Energy believes it is in material compliance with all applicable laws and regulations.

Refer to "Environmental Laws and Regulations" in Item 1 of this Form 10-K for additional information 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, 2021, 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, 2021, MidAmerican Energy would have been required to post $60 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 structures administered by various state commissions and the FERC. Under these rate 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.

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 the 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 $473 million and total regulatory liabilities were $1,080 million as of December 31, 2021. 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.

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, if any, is not expected to have a material impact on its consolidated financial results. Refer to Note 9 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding income taxes.

It is probable that MidAmerican Energy will either refund to, or recover from its customers in certain state jurisdiction income tax benefits and expense related to the federal tax rate change from 35% to 21% as a result of 2017 Tax Reform, certain property-related basis differences, and other various differences. As of December 31, 2021, these amounts were recognized as a net regulatory liability of $83 million and will be included in regulated rates when the temporary differences reverse.

Impairment of Goodwill

MidAmerican Funding's Consolidated Balance Sheet as of December 31, 2021, 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. Additionally, no indicators of impairment were identified as of December 31, 2021. 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, 2021, MidAmerican Energy recognized a net liability totaling $54 million for the funded status of its defined benefit pension and other postretirement benefit plans. As of December 31, 2021, amounts not yet recognized as a component of net periodic benefit cost that were included in regulatory assets and regulatory liabilities totaled $42 million and $55 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 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 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, 2021.

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 2025 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 the 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, 2021 Benefit Obligations:				
Discount rate	$ (38)	$ 45	$ (13)	$ 15
Effect on 2021 Periodic Cost:				
Discount rate	1	—	—	1
Expected rate of return on plan assets	(3)	3	(1)	1

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

Revenue Recognition - Unbilled Revenue

Revenue from electric and natural gas customers is recognized as electricity or natural gas is delivered or services are provided. The determination of customer billings is based on a systematic reading of customer meters and applicable rates. 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. Unbilled revenue was $85 million as of December 31, 2021. 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 sales among customer classes. Unbilled revenue is reversed in the following month, and billed revenue is recorded based on the subsequent meter readings.

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, 2021 and 2020, MidAmerican Energy had short- and long-term variable-rate obligations totaling $370 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, 2021, 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, 2021 and 2020.

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, 2021, MidAmerican Energy's aggregate direct credit exposure from electric wholesale marketing counterparties was not material.

Item 8. Financial Statements and Supplementary Data

MidAmerican Energy Company

Report of Independent Registered Public Accounting Firm	268
Balance Sheets	270
Statements of Operations	272
Statements of Changes in Shareholder's Equity	273
Statements of Cash Flows	274
Notes to Financial Statements	275

MidAmerican Funding, LLC and Subsidiaries

Report of Independent Registered Public Accounting Firm	304
Consolidated Balance Sheets	306
Consolidated Statements of Operations	308
Consolidated Statements of Changes in Member's Equity	309
Consolidated Statements of Cash Flows	310
Notes to Consolidated Financial Statements	311

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, 2021 and 2020, 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, 2021, 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, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021, 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 — Impact of Rate Regulation on the Financial Statements — Refer to Notes 2 and 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 it meets 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 impacts multiple financial statement line items and disclosures, such as property, plant and equipment, net; regulatory assets and liabilities; deferred income taxes; operating revenue; operations and maintenance expense; depreciation and amortization expense and income tax benefit.

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 impact 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 impact of rate regulation as a critical audit matter due to the significant judgments made by management to support its assertions about impacted account balances and disclosures and the high degree of subjectivity involved in assessing the impact of future 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 future 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 impacts of rate regulation, including the balances recorded and regulatory developments.
- We read relevant regulatory orders issued by the Commissions, regulatory statutes, interpretations, procedural memorandums, filings made by interveners, and other publicly available information 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 evaluated the external information and compared to management's recorded regulatory asset and liability balances for completeness.
- For regulatory matters in process, we inspected MidAmerican Energy's filings with the Commissions and the filings with the Commissions by intervenors that may impact MidAmerican Energy's future rates, for any evidence that might contradict management's assertions.
- 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 25, 2022

We have served as MidAmerican Energy's auditor since 1999.

MIDAMERICAN ENERGY COMPANY
BALANCE SHEETS
(Amounts in millions)

	As of December 31,	
	2021	**2020**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 232	$ 38
Trade receivables, net	526	234
Income tax receivable	79	—
Inventories	234	278
Other current assets	123	73
Total current assets	1,194	623
Property, plant and equipment, net	20,301	19,279
Regulatory assets	473	392
Investments and restricted investments	1,026	911
Other assets	263	232
Total assets	$ 23,257	$ 21,437

The accompanying notes are an integral part of these financial statements.

MIDAMERICAN ENERGY COMPANY
BALANCE SHEETS (continued)
(Amounts in millions)

	As of December 31,	
	2021	**2020**
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities:		
Accounts payable	$ 531	$ 408
Accrued interest	84	78
Accrued property, income and other taxes	158	161
Other current liabilities	145	183
Total current liabilities	918	830
Long-term debt	7,721	7,210
Regulatory liabilities	1,080	1,111
Deferred income taxes	3,389	3,054
Asset retirement obligations	714	709
Other long-term liabilities	475	458
Total liabilities	14,297	13,372
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	8,399	7,504
Total shareholder's equity	8,960	8,065
Total liabilities and shareholder's equity	$ 23,257	$ 21,437

The accompanying notes are an integral part of these financial statements.

MIDAMERICAN ENERGY COMPANY
STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2021	**2020**	**2019**
Operating revenue:			
Regulated electric	$ 2,529	$ 2,139	$ 2,237
Regulated natural gas and other	1,018	581	688
Total operating revenue	3,547	2,720	2,925
Operating expenses:			
Cost of fuel and energy	539	339	399
Cost of natural gas purchased for resale and other	761	328	413
Operations and maintenance	775	754	800
Depreciation and amortization	914	716	639
Property and other taxes	142	135	126
Total operating expenses	3,131	2,272	2,377
Operating income	416	448	548
Other income (expense):			
Interest expense	(302)	(304)	(281)
Allowance for borrowed funds	13	15	27
Allowance for equity funds	39	45	78
Other, net	53	52	50
Total other income (expense)	(197)	(192)	(126)
Income before income tax benefit	219	256	422
Income tax benefit	(675)	(570)	(371)
Net income	$ 894	$ 826	$ 793

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, 2018	$ —	$ 561	$ 5,885	$ 6,446
Net income	—	—	793	793
Other equity transactions	—	—	1	1
Balance, December 31, 2019	—	561	6,679	7,240
Net income	—	—	826	826
Other equity transactions	—	—	(1)	(1)
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

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,		
	2021	**2020**	**2019**
Cash flows from operating activities:			
Net income	$ 894	$ 826	$ 793
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	914	716	639
Amortization of utility plant to other operating expenses	34	34	33
Allowance for equity funds	(39)	(45)	(78)
Deferred income taxes and amortization of investment tax credits	153	208	154
Settlements of asset retirement obligations	(103)	(124)	(14)
Other, net	21	(18)	4
Changes in other operating assets and liabilities:			
Trade receivables and other assets	(293)	48	60
Inventories	44	(52)	(22)
Pension and other postretirement benefit plans, net	(4)	(19)	(10)
Accrued property, income and other taxes, net	(71)	(64)	(76)
Accounts payable and other liabilities	67	33	7
Net cash flows from operating activities	1,617	1,543	1,490
Cash flows from investing activities:			
Capital expenditures	(1,912)	(1,836)	(2,810)
Purchases of marketable securities	(213)	(281)	(156)
Proceeds from sales of marketable securities	207	269	138
Proceeds from sales of other investments	—	2	1
Other investment proceeds	1	9	13
Other, net	6	11	13
Net cash flows from investing activities	(1,911)	(1,826)	(2,801)
Cash flows from financing activities:			
Proceeds from long-term debt	492	—	2,326
Repayments of long-term debt	(1)	—	(500)
Net repayments of short-term debt	—	—	(240)
Other, net	(3)	(2)	(1)
Net cash flows from financing activities	488	(2)	1,585
Net change in cash and cash equivalents and restricted cash and cash equivalents	194	(285)	274
Cash and cash equivalents and restricted cash and cash equivalents at beginning of year	45	330	56
Cash and cash equivalents and restricted cash and cash equivalents at end of year	$ 239	$ 45	$ 330

The accompanying notes are an integral part of these financial statements.

MIDAMERICAN ENERGY COMPANY
NOTES TO FINANCIAL STATEMENTS

(1) Organization and Operations

MidAmerican Energy Company ("MidAmerican Energy") is a public utility with electric and natural gas operations and is the principal subsidiary of MHC Inc. ("MHC"). MHC is a holding company that conducts no business other than the ownership of its subsidiaries. MHC's nonregulated subsidiary is Midwest Capital Group, Inc. MHC is the direct wholly owned subsidiary of MidAmerican Funding, LLC, ("MidAmerican Funding"), which is an Iowa limited liability company with Berkshire Hathaway Energy Company ("BHE") as its sole member. BHE is a holding company based in Des Moines, Iowa that 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, 2021, 2020 and 2019.

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 in 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 Equivalents and Restricted Cash and Cash Equivalents and Investments

Cash equivalents consist of funds invested in money market mutual funds, United States 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 amounts are included in other current assets and investments and restricted investments on the Balance Sheets.

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):

	2021	2020	2019
Beginning balance	$ 12	$ 5	$ 7
Charged to operating costs and expenses, net	10	12	9
Write-offs, net	(10)	(5)	(11)
Ending balance	$ 12	$ 12	$ 5

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 $135 million and $129 million as of December 31, 2021 and 2020, respectively, coal stocks, totaling $63 million and $119 million as of December 31, 2021 and 2020, respectively, and natural gas in storage, totaling $30 million and $26 million as of December 31, 2021 and 2020, 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 $27 million and $10 million higher as of December 31, 2021 and 2020, 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 utility plant, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or 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. The impacts of regulation are considered when evaluating the carrying value of regulated assets. For all other assets, 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, 2021 and 2020, unbilled revenue was $85 million and $95 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, 2021 and 2020, was $230 million and $22 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 United States 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 that are 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 generally deferred and amortized over the estimated useful lives of the related properties or as prescribed by various regulatory commissions.

Investment tax credits are generally 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.

(3) Property, Plant and Equipment, Net

Property, plant and equipment, net consists of the following as of December 31 (in millions):

	Depreciable Life	2021	2020
Utility plant in-service, net:			
Generation	20-70 years	$ 17,397	$ 16,980
Transmission	52-75 years	2,474	2,365
Electric distribution	20-75 years	4,661	4,369
Natural gas distribution	29-75 years	2,039	1,955
Utility plant in-service		26,571	25,669
Accumulated depreciation and amortization		(7,376)	(6,902)
Utility plant in-service, net		19,195	18,767
Nonregulated property, net:			
Nonregulated property gross	20-50 years	7	7
Accumulated depreciation and amortization		(1)	(1)
Nonregulated property, net		6	6
		19,201	18,773
Construction work-in-progress		1,100	506
Property, plant and equipment, net		$ 20,301	$ 19,279

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:

	2021	2020	2019
Electric	3.3 %	3.2 %	3.1 %
Natural gas	2.8 %	2.8 %	2.8 %

(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, 2021 (dollars in millions):

	Company Share	Plant in Service	Accumulated Depreciation and Amortization	Construction Work-in-Progress
Louisa Unit No. 1	88 %	$ 864	$ 501	$ 20
Quad Cities Unit Nos. 1 & 2[(1)]	25	732	452	9
Walter Scott, Jr. Unit No. 3	79	949	518	15
Walter Scott, Jr. Unit No. 4[(2)]	60	225	134	8
George Neal Unit No. 4	41	318	184	4
Ottumwa Unit No. 1	52	674	264	11
George Neal Unit No. 3	72	528	286	9
Transmission facilities	Various	263	100	4
Total		$ 4,553	$ 2,439	$ 80

(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 $561 million and $127 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	2021	2020
Asset retirement obligations[(1)]	6 years	$ 393	$ 298
Employee benefit plans[(2)]	13 years	42	66
Unrealized loss on regulated derivative contracts	1 year	5	—
Other	Various	33	28
Total		$ 473	$ 392

(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 $470 million and $389 million as of December 31, 2021 and 2020, 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	2021	2020
Cost of removal accrual[1]	29 years	$ 394	$ 466
Asset retirement obligations[2]	31 years	341	300
Iowa electric revenue sharing accrual[3]	1 year	115	—
Deferred income taxes[4]	Various	83	263
Employee benefit plans[5]	9 years	55	20
Pre-funded AFUDC on transmission MVPs[6]	51 years	34	35
Unrealized gain on regulated derivative contracts	1 year	26	2
Other	Various	32	25
Total		$ 1,080	$ 1,111

(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 current-year accruals under a regulatory arrangement in Iowa in which equity returns exceeding specified thresholds reduce utility plant upon final determination.

(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 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) 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.

Natural Gas Purchased for Resale

In February 2021, severe cold weather over the central United States caused disruptions in natural gas supply from the southern part of the United States. These disruptions, combined with increased demand, resulted in historically high prices for natural gas purchased for resale to MidAmerican Energy's retail customers and caused an approximate $245 million increase in natural gas costs above those normally expected. These increased costs are reflected in cost of natural gas purchased for resale and other on the Statement of Operations and their recovery through the Purchased Gas Adjustment Clause is reflected in regulated natural gas and other revenue.

To mitigate the impact to MidAmerican Energy's customers, the IUB ordered the recovery of these higher costs to be applied to customer bills over the period April 2021 through April 2022 based on a customer's monthly natural gas usage. The unbilled portion of these costs as of December 31, 2021, is reflected in trade receivables, net on the Balance Sheet. While sufficient liquidity is available to MidAmerican Energy, the increased costs and longer recovery period resulted in higher working capital requirements during the year ended December 31, 2021.

(6) Investments and Restricted Investments

Investments and restricted investments consists of the following amounts as of December 31 (in millions):

	2021	2020
Nuclear decommissioning trust	$ 768	$ 676
Rabbi trusts	233	211
Other	25	24
Total	$ 1,026	$ 911

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, 2021 and 2020, the fair value of the trust's funds was invested as follows: 56% and 56%, respectively, in domestic common equity securities, 30% and 30%, respectively, in United States government securities, 12% 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 Operation.

(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):

	2021	2020
Credit facilities	$ 1,505	$ 1,505
Less:		
Variable-rate tax-exempt bond support	(370)	(370)
Net credit facilities	$ 1,135	$ 1,135

As of December 31, 2021, MidAmerican Energy has a $1.5 billion unsecured credit facility expiring in June 2024. In June 2021, MidAmerican Energy amended and restated its existing $900 million unsecured credit facility expiring June 2022. The amendment increased the commitment of the lenders to $1.5 billion, extended the expiration date to June 2024 and increased the available maturity extension options to an unlimited number, 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 Eurodollar rate 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 2022 and has a variable interest rate based on the Eurodollar rate plus a spread.

As of December 31, 2020, in addition to the $900 million unsecured credit facility discussed above, MidAmerican Energy had a $600 million unsecured credit facility expiring August 2021, which was terminated in June 2021. MidAmerican Energy had no commercial paper borrowings outstanding of as of December 31, 2021 and 2020. 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, 2021, 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, 2022.

(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	2021	2020
First mortgage bonds:			
3.70%, due 2023	$ 250	$ 250	$ 249
3.50%, due 2024	500	501	501
3.10%, due 2027	375	373	373
3.65%, due 2029	850	860	862
4.80%, due 2043	350	346	346
4.40%, due 2044	400	395	395
4.25%, due 2046	450	446	445
3.95%, due 2047	475	470	470
3.65%, due 2048	700	689	689
4.25%, due 2049	900	874	873
3.15%, due 2050	600	592	592
2.70%, due 2052	500	492	—
Notes:			
6.75% Series, due 2031	400	397	397
5.75% Series, due 2035	300	298	298
5.80% Series, due 2036	350	348	348
Transmission upgrade obligations, 3.35% to 7.95%, due 2036 to 2041	38	22	4
Variable-rate tax-exempt bond obligation series: (weighted average interest rate-2021-0.13%, 2020-0.14%):			
Due 2023, issued in 1993	7	7	7
Due 2023, issued in 2008	57	57	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	29
Due 2047	150	149	149
Total	$ 7,808	$ 7,721	$ 7,210

The annual repayments of MidAmerican Energy's long-term debt for the years beginning January 1, 2022, and thereafter, excluding unamortized premiums, discounts and debt issuance costs, are as follows (in millions):

2022	$ —
2023	316
2024	537
2025	15
2026	2
2027 and thereafter	6,938

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 $22 billion of MidAmerican Energy's eligible property, based on original cost, was subject to the lien of the mortgage as of December 31, 2021. 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, 2021 and 2020. 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, 2021, 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, 2021, MidAmerican Energy's common equity ratio was 53% 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 $3.3 billion as of December 31, 2021, without falling below 42%.

(9) Income Taxes

MidAmerican Energy's income tax benefit consists of the following for the years ended December 31 (in millions):

	2021	2020	2019
Current:			
Federal	$ (736)	$ (684)	$ (478)
State	(92)	(94)	(47)
	(828)	(778)	(525)
Deferred:			
Federal	189	201	166
State	(35)	8	(11)
	154	209	155
Investment tax credits	(1)	(1)	(1)
Total	$ (675)	$ (570)	$ (371)

A reconciliation of the federal statutory income tax rate to MidAmerican Energy's effective income tax rate applicable to income before income tax benefit is as follows for the years ended December 31:

	2021	2020	2019
Federal statutory income tax rate	21 %	21 %	21 %
Income tax credits	(262)	(199)	(90)
State income tax, net of federal income tax benefit	(46)	(27)	(11)
Effects of ratemaking	(20)	(17)	(8)
Other, net	(1)	(1)	—
Effective income tax rate	(308)%	(223)%	(88)%

Income tax credits relate primarily to production tax credits ("PTC") earned by MidAmerican Energy'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.

MidAmerican Energy's net deferred income tax liability consists of the following as of December 31 (in millions):

	2021	2020
Deferred income tax assets:		
Regulatory liabilities	$ 240	$ 288
Asset retirement obligations	220	229
State carryforwards	55	52
Employee benefits	26	42
Other	30	40
Total deferred income tax assets	571	651
Valuation allowances	(1)	(25)
Total deferred income tax assets, net	570	626
Deferred income tax liabilities:		
Depreciable property	(3,843)	(3,583)
Regulatory assets	(112)	(97)
Other	(4)	—
Total deferred income tax liabilities	(3,959)	(3,680)
Net deferred income tax liability	$ (3,389)	$ (3,054)

As of December 31, 2021, MidAmerican Energy's state tax carryforwards, principally related to $823 million of net operating losses, expire at various intervals between 2022 and 2040.

The United States 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 state income tax returns have expired through December 31, 2011, for Michigan and Nebraska, and through December 31, 2017, for Illinois, Indiana, Iowa, Kansas and Missouri, except for the impact of any federal audit adjustments. The statute of limitations expiring 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):

	2021	2020
Beginning balance	$ 8	$ 8
Additions based on tax positions related to the current year	16	4
Reductions based on tax positions related to the current year	(11)	(3)
Reductions for tax positions of prior years	—	(1)
Ending balance	$ 13	$ 8

As of December 31, 2021, MidAmerican Energy had unrecognized tax benefits totaling $33 million that, if recognized, would have an impact on the effective tax rate. The remaining unrecognized tax benefits relate to tax positions for which ultimate deductibility is highly certain but for which there is uncertainty as to the timing of such deductibility. Recognition of these tax benefits, other than applicable interest and penalties, would not affect MidAmerican Energy's effective income tax rate.

(10) Employee Benefit Plans

Defined Benefit Plan

MidAmerican Energy sponsors a noncontributory defined benefit pension plan covering a majority of all employees of BHE and its domestic energy subsidiaries other than PacifiCorp and NV Energy, Inc. Benefit obligations under the plan are based on a cash balance arrangement for salaried employees and most union employees and final average pay formulas for other union employees. MidAmerican Energy also maintains noncontributory, nonqualified defined benefit supplemental executive retirement plans ("SERP") for certain active and retired participants. In 2021, the defined benefit pension plan recorded a settlement gain of $5 million for previously unrecognized gains as a result of excess lump sum distributions over the defined threshold for the year ended December 31, 2021.

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.

On November 1, 2020, BHE completed its acquisition of substantially all of the natural gas transmission and storage business of Dominion Energy, Inc. and Dominion Energy Questar Corporation, exclusive of Dominion Energy Questar Pipeline, LLC and related entities (the "GT&S Transaction"). Defined benefit pension and postretirement benefits provided to the employees of GT&S are administered in the respective plans sponsored by MidAmerican Energy. Initial pension and postretirement plan liabilities of $81 million and $37 million, respectively, resulted from the GT&S Transaction and are included in plan obligations and affiliate receivables on MidAmerican Energy's Balance Sheet.

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 2021, 2020 and 2019, MidAmerican Energy's share of the pension net periodic benefit (credit) cost was $(20) million, $(13) million and $(8) million, respectively. MidAmerican Energy's share of the other postretirement net periodic benefit (credit) cost in 2021, 2020 and 2019 totaled $1 million, $(5) 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		
	2021	2020	2019	2021	2020	2019
Service cost	$ 20	$ 8	$ 6	$ 9	$ 4	$ 5
Interest cost	22	25	30	8	7	10
Expected return on plan assets	(37)	(40)	(41)	(10)	(14)	(13)
Settlement	(5)	—	—	—	—	—
Net amortization	1	1	1	(4)	(5)	(3)
Net periodic benefit cost (credit)	$ 1	$ (6)	$ (4)	$ 3	$ (8)	$ (1)

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	
	2021	2020	2021	2020
Plan assets at fair value, beginning of year	$ 718	$ 717	$ 278	$ 272
Employer contributions	8	6	10	3
Participant contributions	—	—	1	1
Actual return on plan assets	58	55	34	15
Settlement	(46)	—	—	—
Benefits paid	(34)	(60)	(15)	(13)
Plan assets at fair value, end of year	$ 704	$ 718	$ 308	$ 278

The following table is a reconciliation of the benefit obligations for the years ended December 31 (in millions):

	Pension		Other Postretirement	
	2021	2020	2021	2020
Benefit obligation, beginning of year	$ 845	$ 763	$ 304	$ 226
Service cost	20	8	9	4
Interest cost	22	25	8	7
Participant contributions	—	—	1	1
Actuarial (gain) loss	(25)	28	(18)	42
Plan amendments	—	—	1	—
Settlement	(46)	—	—	—
Acquisition	(1)	81	(5)	37
Benefits paid	(34)	(60)	(15)	(13)
Benefit obligation, end of year	$ 781	$ 845	$ 285	$ 304
Accumulated benefit obligation, end of year	$ 721	$ 773		

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	
	2021	2020	2021	2020
Plan assets at fair value, end of year	$ 704	$ 718	$ 308	$ 278
Less - Benefit obligation, end of year	781	845	285	304
Funded status	$ (77)	$ (127)	$ 23	$ (26)
Amounts recognized on the Balance Sheets:				
Other assets	$ 34	$ —	$ 23	$ —
Other current liabilities	(7)	(7)	—	—
Other liabilities	(104)	(120)	—	(26)
Amounts recognized	$ (77)	$ (127)	$ 23	$ (26)

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 $143 million and $130 million as of December 31, 2021 and 2020. These assets are not included in the plan assets in the above table, but are reflected in investments and restricted investments on the Balance Sheets. The accumulated benefit obligation and projected benefit obligation for the SERP was $111 million and $111 million for 2021 and $117 million and $117 million for 2020, 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	
	2021	**2020**	**2021**	**2020**
Net (gain) loss	$ (25)	$ 18	$ 2	$ 45
Prior service (credit) cost	—	—	(3)	(9)
Total	$ (25)	$ 18	$ (1)	$ 36

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, 2021 and 2020 is as follows (in millions):

	Regulatory Asset	Regulatory Liability	Receivables (Payables) with Affiliates	Total
Pension				
Balance, December 31, 2019	$ 19	$ (32)	$ 18	$ 5
Net (gain) loss arising during the year	3	12	(1)	14
Net amortization	(1)	—	—	(1)
Total	2	12	(1)	13
Balance, December 31, 2020	21	(20)	17	18
Net loss (gain) arising during the year	2	(40)	(9)	(47)
Net amortization	(1)	—	—	(1)
Settlement	—	5	—	5
Total	1	(35)	(9)	(43)
Balance, December 31, 2021	$ 22	$ (55)	$ 8	$ (25)

	Regulatory Asset	Receivables (Payables) with Affiliates	Total
Other Postretirement			
Balance, December 31, 2019	$ 7	$ (17)	$ (10)
Net gain arising during the year	34	7	41
Net amortization	4	1	5
Total	38	8	46
Balance, December 31, 2020	45	(9)	36
Net loss arising during the year	(29)	(13)	(42)
Net prior service cost arising during the year	1	—	1
Net amortization	3	1	4
Total	(25)	(12)	(37)
Balance, December 31, 2021	$ 20	$ (21)	$ (1)

Plan Assumptions

Assumptions used to determine benefit obligations and net periodic benefit cost were as follows:

	Pension			Other Postretirement		
	2021	2020	2019	2021	2020	2019
Benefit obligations as of December 31:						
Discount rate	3.05 %	2.75 %	3.40 %	2.95 %	2.65 %	3.20 %
Rate of compensation increase	2.75 %	2.75 %	2.75 %	N/A	N/A	N/A
Interest crediting rates for cash balance plan						
2019	N/A	N/A	3.40 %	N/A	N/A	N/A
2020	N/A	2.27 %	2.27 %	N/A	N/A	N/A
2021	1.19 %	0.99 %	2.27 %	N/A	N/A	N/A
2022	1.19 %	0.99 %	2.27 %	N/A	N/A	N/A
2023	1.19 %	0.99 %	2.27 %	N/A	N/A	N/A
2024 and beyond	1.19 %	0.99 %	2.27 %	N/A	N/A	N/A
Net periodic benefit cost for the years ended December 31:						
Discount rate	2.75 %	3.40 %	4.25 %	2.65 %	3.20 %	4.15 %
Expected return on plan assets[(1)]	5.60 %	6.25 %	6.50 %	4.00 %	6.00 %	6.25 %
Rate of compensation increase	2.75 %	2.75 %	2.75 %	N/A	N/A	N/A
Interest crediting rates for cash balance plan	1.19 %	2.27 %	3.40 %	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 2.39% for 2021, 4.62% for 2020 and 4.62% for 2019.

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.

	2021	2020
Assumed healthcare cost trend rates as of December 31:		
Healthcare cost trend rate assumed for next year	5.90 %	6.20 %
Rate that the cost trend rate gradually declines to	5.00 %	5.00 %
Year that the rate reaches the rate it is assumed to remain at	2025	2025

Contributions and Benefit Payments

Employer contributions to the pension and other postretirement benefit plans are expected to be $7 million and $3 million, respectively, during 2022. 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 2022 through 2026 and for the five years thereafter are summarized below (in millions):

	Projected Benefit Payments	
	Pension	**Other Postretirement**
2022	$ 56	$ 21
2023	55	22
2024	54	22
2025	52	22
2026	51	22
2027-2031	229	98

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 advisors to manage 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, 2021:

	Pension	**Other Postretirement**
	%	%
Debt securities[1]	60-80	25-35
Equity securities[1]	20-40	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, 2021:				
Cash equivalents	$ —	$ 27	$ —	$ 27
Debt securities:				
United States government obligations	33	—	—	33
International government obligations	—	—	—	—
Corporate obligations	—	242	—	242
Municipal obligations	—	18	—	18
Agency, asset and mortgage-backed obligations	—	17	—	17
Equity securities:				
United States companies	35	—	—	35
Total assets in the hierarchy	$ 68	$ 304	$ —	372
Investment funds[2] measured at net asset value				332
Total assets measured at fair value				$ 704
As of December 31, 2020:				
Cash equivalents	$ —	$ 26	$ —	$ 26
Debt securities:				
United States government obligations	14	—	—	14
International government obligations	—	—	—	—
Corporate obligations	—	160	—	160
Municipal obligations	—	17	—	17
Agency, asset and mortgage-backed obligations	—	—	—	—
Equity securities:				
United States companies	65	—	—	65
Total assets in the hierarchy	$ 79	$ 203	$ —	282
Investment funds[2] measured at net asset value				393
Real estate funds measured at net asset value				43
Total assets measured at fair value				$ 718

(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 56% and 44%, respectively, for 2021 and 65% and 35%, respectively, for 2020. Additionally, these funds are invested in United States and international securities of approximately 90% and 10%, respectively, for 2021 and 82% and 18%, respectively, for 2020.

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, 2021:				
Cash equivalents	$ 8	$ —	$ —	$ 8
Debt securities:				
United States government obligations	3	—	—	3
Corporate obligations	—	6	—	6
Municipal obligations	—	28	—	28
Agency, asset and mortgage-backed obligations	—	3	—	3
Equity securities:				
Investment funds[2]	260	—	—	260
Total assets measured at fair value	$ 271	$ 37	$ —	$ 308
As of December 31, 2020:				
Cash equivalents	$ 11	$ —	$ —	$ 11
Debt securities:				
United States government obligations	3	—	—	3
Corporate obligations	—	7	—	7
Municipal obligations	—	65	—	65
Agency, asset and mortgage-backed obligations	—	3	—	3
Equity securities:				
Investment funds[2]	189	—	—	189
Total assets measured at fair value	$ 203	$ 75	$ —	$ 278

(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 82% and 18%, respectively, for 2021 and 56% and 44%, respectively, for 2020. Additionally, these funds are invested in United States and international securities of approximately 82% and 18%, respectively, for 2021 and 56% and 44%, respectively, for 2020.

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 $27 million, $26 million, and $23 million for the years ended December 31, 2021, 2020 and 2019, 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.

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 $394 million and $466 million as of December 31, 2021 and 2020, respectively.

The following table presents MidAmerican Energy's ARO liabilities by asset type as of December 31 (in millions):

	2021	2020
Quad Cities Station	$ 427	$ 376
Fossil-fueled generating facilities	161	255
Wind-powered generating facilities	197	185
Other	2	2
Total asset retirement obligations	$ 787	$ 818
Quad Cities Station nuclear decommissioning trust funds[(1)]	$ 768	$ 676

(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):

	2021	2020
Beginning balance	$ 818	$ 839
Change in estimated costs	35	47
Additions	6	23
Retirements	(103)	(124)
Accretion	31	33
Ending balance	$ 787	$ 818
Reflected as:		
Other current liabilities	$ 73	$ 109
Asset retirement obligations	714	709
	$ 787	$ 818

Retirements in 2021 and 2020 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, 2021:					
Assets:					
Commodity derivatives	$ —	$ 32	$ 3	$ (7)	$ 28
Money market mutual funds	228	—	—	—	228
Debt securities:					
United States government obligations	232	—	—	—	232
International government obligations	—	2	—	—	2
Corporate obligations	—	90	—	—	90
Municipal obligations	—	3	—	—	3
Agency, asset and mortgage-backed obligations	—	2	—	—	2
Equity securities:					
United States companies	428	—	—	—	428
International companies	10	—	—	—	10
Investment funds	18	—	—	—	18
	$ 916	$ 129	$ 3	$ (7)	$ 1,041
Liabilities - commodity derivatives	$ —	$ (6)	$ (8)	$ 12	$ (2)
As of December 31, 2020					
Assets:					
Commodity derivatives	$ —	$ 4	$ 5	$ (5)	$ 4
Money market mutual funds	41	—	—	—	41
Debt securities:					
United States government obligations	200	—	—	—	200
International government obligations	—	5	—	—	5
Corporate obligations	—	73	—	—	73
Municipal obligations	—	2	—	—	2
Agency, asset and mortgage-backed obligations	—	6	—	—	6
Equity securities:					
United States companies	381	—	—	—	381
International companies	9	—	—	—	9
Investment funds	17	—	—	—	17
	$ 648	$ 90	$ 5	$ (5)	$ 738
Liabilities - commodity derivatives	$ —	$ (4)	$ (3)	$ 5	$ (2)

(1) Represents netting under master netting arrangements and a net cash collateral receivable of $5 million and $— million as of December 31, 2021 and 2020, 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.

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):

	2021		2020	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 7,721	$ 9,037	$ 7,210	$ 9,130

(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, 2021, are as follows (in millions):

	2022	2023	2024	2025	2026	2027 and Thereafter	Total
Contract type:							
Coal and natural gas for generation	$ 127	$ 81	$ 55	$ 27	$ —	$ —	$ 290
Electric capacity and transmission	32	32	32	32	32	25	185
Natural gas contracts for gas operations	156	59	28	20	11	21	295
Construction commitments	806	19	12	11	4	—	852
Easements	40	41	42	43	44	1,574	1,784
Maintenance, services and other	165	166	131	99	98	260	919
	$ 1,326	$ 398	$ 300	$ 232	$ 189	$ 1,880	$ 4,325

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 2025.

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-powered generating facilities 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-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 2030.

Environmental Laws and Regulations

MidAmerican Energy is subject to federal, state and local laws and regulations regarding air and water quality, emissions performance standards, climate change, coal combustion byproduct disposal, hazardous and solid waste disposal, protected species 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.

Transmission Rates

MidAmerican Energy's wholesale transmission rates are set annually using FERC-approved formula rates subject to true-up for actual cost of service. MidAmerican Energy is authorized by the FERC to include a 0.50% adder beyond the approved base return on equity ("ROE") effective January 2015. Prior to September 2016, the rates in effect were based on a 12.38% ROE. In November 2013 and February 2015, a coalition of intervenors filed successive complaints with the FERC requesting that the 12.38% ROE no longer be found just and reasonable and sought to reduce the base ROE to 9.15% and 8.67%, respectively. In September 2016, the FERC issued an order for the first complaint, which reduces the base ROE to 10.32% and required refunds, plus interest, for the period from November 2013 through February 2015. Customer refunds relative to the first complaint occurred in February 2017. In November 2019, the FERC issued an order addressing the second complaint and issues on appeal in the first complaint. The order established an ROE of 9.88% (10.38% including the 0.50% adder) for the 15-month refund period of the first complaint and prospectively from September 2016 forward. In May 2020, the FERC issued an order on rehearing of the November 2019 order. The May 2020 order affirmed the FERC's prior decision to dismiss the second complaint and established an ROE of 10.02% (10.52% including the 0.50% adder) for the 15-month refund period of the first complaint and prospectively from September 2016 to the date of the May 2020 order. These orders continue to be subject to judicial appeal. MidAmerican Energy cannot predict the ultimate outcome of these matters and, as of December 31, 2021, has accrued a $8 million liability for refunds of amounts collected under the higher ROE during the periods covered by both complaints.

Legal Matters

MidAmerican Energy is party to a variety of legal actions arising out of the normal course of business. Plaintiffs occasionally seek punitive or exemplary damages. MidAmerican Energy does not believe that such normal and routine litigation will have a material impact on its financial results.

(14) Revenue from Contracts with Customers

MidAmerican Energy uses a single five-step model to identify and recognize Customer Revenue upon transfer of control of promised goods or services to customers in an amount that reflects the consideration to which it expects to be entitled in exchange for those goods or services. The following table summarizes MidAmerican Energy's revenue by line of business and customer class, including a reconciliation to MidAmerican Energy's reportable segment information included in Note 18, (in millions):

	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

	For the Year Ended December 31, 2020			
	Electric	Natural Gas	Other	Total
Customer Revenue:				
Retail:				
Residential	$ 685	$ 342	$ —	$ 1,027
Commercial	304	111	—	415
Industrial	804	14	—	818
Natural gas transportation services	—	36	—	36
Other retail	131	2	—	133
Total retail	1,924	505	—	2,429
Wholesale	133	66	—	199
Multi-value transmission projects	60	—	—	60
Other Customer Revenue	—	—	8	8
Total Customer Revenue	2,117	571	8	2,696
Other revenue	22	2	—	24
Total operating revenue	$ 2,139	$ 573	$ 8	$ 2,720

	For the Year Ended December 31, 2019			
	Electric	Natural Gas	Other	Total
Customer Revenue:				
Retail:				
Residential	$ 672	$ 383	$ —	$ 1,055
Commercial	322	132	—	454
Industrial	799	17	—	816
Natural gas transportation services	—	38	—	38
Other retail	145	—	—	145
Total retail	1,938	570	—	2,508
Wholesale	221	88	—	309
Multi-value transmission projects	57	—	—	57
Other Customer Revenue	—	—	28	28
Total Customer Revenue	2,216	658	28	2,902
Other revenue	21	2	—	23
Total operating revenue	$ 2,237	$ 660	$ 28	$ 2,925

(15) 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):

	2021	2020	2019
Non-service cost components of postretirement employee benefit plans	$ 26	$ 24	$ 17
Corporate-owned life insurance income	21	16	24
Gains on disposition of assets	—	6	—
Interest income and other, net	6	6	9
Total	$ 53	$ 52	$ 50

(16) Supplemental Cash Flow Disclosures

Cash equivalents consist of funds invested in money market mutual funds, United States 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 as of December 31, 2021 and 2020 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, 2021 and 2020 as presented in 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,	
	2021	2020
Cash and cash equivalents	$ 232	$ 38
Restricted cash and cash equivalents in other current assets	7	7
Total cash and cash equivalents and restricted cash and cash equivalents	$ 239	$ 45

The summary of supplemental cash flow disclosures as of and for the years ending December 31 is as follows (in millions):

	2021	2020	2019
Supplemental disclosure of cash flow information:			
Interest paid, net of amounts capitalized	$ 279	$ 286	$ 224
Income taxes received, net	$ 746	$ 709	$ 450
Supplemental disclosure of non-cash investing transactions:			
Accounts payable related to utility plant additions	$ 257	$ 227	$ 337

(17) 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 $66 million, $47 million and $43 million for 2021, 2020 and 2019, respectively.

MidAmerican Energy reimbursed BHE in the amount of $72 million, $15 million and $14 million in 2021, 2020 and 2019, respectively, for its share of corporate expenses.

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 $132 million, $129 million and $139 million in 2021, 2020 and 2019, respectively. Additionally, in 2020, MidAmerican Energy paid $7 million to BHE Renewables, LLC, a wholly owned subsidiary of BHE, for the purchase of wind turbine components.

MidAmerican Energy had accounts receivable from affiliates of $10 million and $12 million as of December 31, 2021 and 2020, respectively, that are included in other current assets on the Balance Sheets. MidAmerican Energy also had accounts payable to affiliates of $17 million and $13 million as of December 31, 2021 and 2020, 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 United States federal income tax return. For current federal and state income taxes, MidAmerican Energy had a receivable from BHE of $79 million as of December 31, 2021, and a payable to BHE of $14 million as of December 31, 2020. MidAmerican Energy received net cash payments for federal and state income taxes from BHE totaling $746 million, $709 million and $450 million for the years ended December 31, 2021, 2020 and 2019, 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, as well as the initial liabilities associated with BHE's acquisition of GT&S. 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 $124 million and $146 million as of December 31, 2021 and 2020, respectively, and are included in other assets on the Balance Sheets. Similar amounts payable to affiliates totaled $63 million and $49 million as of December 31, 2021 and 2020, 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.

(18) 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 (benefit) expense 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,		
	2021	2020	2019
Operating revenue:			
Regulated electric	$ 2,529	$ 2,139	$ 2,237
Regulated natural gas	1,003	573	660
Other	15	8	28
Total operating revenue	$ 3,547	$ 2,720	$ 2,925
Depreciation and amortization:			
Regulated electric	$ 861	$ 667	$ 593
Regulated natural gas	53	49	46
Total depreciation and amortization	$ 914	$ 716	$ 639
Operating income:			
Regulated electric	$ 358	$ 384	$ 473
Regulated natural gas	58	64	71
Other	—	—	4
Total operating income	$ 416	$ 448	$ 548
Interest expense:			
Regulated electric	$ 279	$ 281	$ 259
Regulated natural gas	23	23	22
Total interest expense	$ 302	$ 304	$ 281

	Years Ended December 31,		
	2021	2020	2019
Income tax (benefit) expense:			
Regulated electric	$ (677)	$ (584)	$ (384)
Regulated natural gas	3	14	12
Other	(1)	—	1
Total income tax (benefit) expense	$ (675)	$ (570)	$ (371)
Net income:			
Regulated electric	$ 844	$ 780	$ 739
Regulated natural gas	50	45	52
Other	—	1	2
Net income	$ 894	$ 826	$ 793
Capital expenditures:			
Regulated electric	$ 1,806	$ 1,704	$ 2,684
Regulated natural gas	106	132	126
Total capital expenditures	$ 1,912	$ 1,836	$ 2,810

	As of December 31,		
	2021	2020	2019
Total assets:			
Regulated electric	$ 21,385	$ 19,892	$ 19,093
Regulated natural gas	1,871	1,544	1,468
Other	1	1	3
Total assets	$ 23,257	$ 21,437	$ 20,564

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, 2021 and 2020, 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, 2021, 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, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021, 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 — Impact of Rate Regulation on the Financial Statements — Refer to Notes 2 and 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 it meets 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 impacts multiple financial statement line items and disclosures, such as property, plant and equipment, net; regulatory assets and liabilities; deferred income taxes; operating revenue; operations and maintenance expense; depreciation and amortization expense and income tax benefit.

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 impact 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 impact of rate regulation as a critical audit matter due to the significant judgments made by management to support its assertions about impacted account balances and disclosures and the high degree of subjectivity involved in assessing the impact of future 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 future 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 impacts of rate regulation, including the balances recorded and regulatory developments.
- We read relevant regulatory orders issued by the Commissions, regulatory statutes, interpretations, procedural memorandums, filings made by interveners, and other publicly available information 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 evaluated the external information and compared to management's recorded regulatory asset and liability balances for completeness.
- For regulatory matters in process, we inspected MidAmerican Funding's filings with the Commissions and the filings with the Commissions by intervenors that may impact MidAmerican Funding's future rates, for any evidence that might contradict management's assertions.
- 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 25, 2022

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,	
	2021	**2020**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 233	$ 39
Trade receivables, net	526	234
Income tax receivable	80	—
Inventories	234	278
Other current assets	123	74
Total current assets	1,196	625
Property, plant and equipment, net	20,302	19,279
Goodwill	1,270	1,270
Regulatory assets	473	392
Investments and restricted investments	1,028	913
Other assets	262	232
Total assets	$ 24,531	$ 22,711

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,	
	2021	**2020**
LIABILITIES AND MEMBER'S EQUITY		
Current liabilities:		
Accounts payable	$ 531	$ 408
Accrued interest	89	83
Accrued property, income and other taxes	158	161
Note payable to affiliate	189	177
Other current liabilities	146	183
Total current liabilities	1,113	1,012
Long-term debt	7,961	7,450
Regulatory liabilities	1,080	1,111
Deferred income taxes	3,387	3,052
Asset retirement obligations	714	709
Other long-term liabilities	475	458
Total liabilities	14,730	13,792
Commitments and contingencies (Note 13)		
Member's equity:		
Paid-in capital	1,679	1,679
Retained earnings	8,122	7,240
Total member's equity	9,801	8,919
Total liabilities and member's equity	$ 24,531	$ 22,711

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,		
	2021	**2020**	**2019**
Operating revenue:			
Regulated electric	$ 2,529	$ 2,139	$ 2,237
Regulated natural gas and other	1,018	589	690
Total operating revenue	3,547	2,728	2,927
Operating expenses:			
Cost of fuel and energy	539	339	399
Cost of natural gas purchased for resale and other	761	329	412
Operations and maintenance	775	755	801
Depreciation and amortization	914	716	639
Property and other taxes	142	135	127
Total operating expenses	3,131	2,274	2,378
Operating income	416	454	549
Other income (expense):			
Interest expense	(319)	(322)	(302)
Allowance for borrowed funds	13	15	27
Allowance for equity funds	39	45	78
Other, net	54	52	52
Total other income (expense)	(213)	(210)	(145)
Income before income tax benefit	203	244	404
Income tax benefit	(680)	(574)	(377)
Net income	$ 883	$ 818	$ 781

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, 2018	$ 1,679	$ 5,650	$ 7,329
Net income	—	781	781
Distribution to member	—	(8)	(8)
Other equity transactions	—	(1)	(1)
Balance, December 31, 2019	1,679	6,422	8,101
Net income	—	818	818
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

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,		
	2021	**2020**	**2019**
Cash flows from operating activities:			
Net income	$ 883	$ 818	$ 781
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	914	716	639
Amortization of utility plant to other operating expenses	34	34	33
Allowance for equity funds	(39)	(45)	(78)
Deferred income taxes and amortization of investment tax credits	153	211	152
Settlements of asset retirement obligations	(103)	(124)	(14)
Other, net	21	(17)	5
Changes in other operating assets and liabilities:			
Trade receivables and other assets	(293)	48	56
Inventories	44	(52)	(22)
Pension and other postretirement benefit plans, net	(4)	(19)	(10)
Accrued property, income and other taxes, net	(71)	(66)	(74)
Accounts payable and other liabilities	66	32	7
Net cash flows from operating activities	1,605	1,536	1,475
Cash flows from investing activities:			
Capital expenditures	(1,912)	(1,836)	(2,810)
Purchases of marketable securities	(213)	(281)	(156)
Proceeds from sales of marketable securities	207	269	138
Proceeds from sales of other investments	—	3	1
Other investment proceeds	1	9	13
Other, net	5	11	13
Net cash flows from investing activities	(1,912)	(1,825)	(2,801)
Cash flows from financing activities:			
Proceeds from long-term debt	492	—	2,326
Repayments of long-term debt	(1)	—	(500)
Net change in note payable to affiliate	12	5	15
Net repayments of short-term debt	—	—	(240)
Other, net	(2)	(1)	(1)
Net cash flows from financing activities	501	4	1,600
Net change in cash and cash equivalents and restricted cash and cash equivalents	194	(285)	274
Cash and cash equivalents and restricted cash and cash equivalents at beginning of year	46	331	57
Cash and cash equivalents and restricted cash and cash equivalents at end of year	$ 240	$ 46	$ 331

The accompanying notes are an integral part of these 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, 2021, 2020 and 2019.

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. 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 2021, 2020 and 2019, MidAmerican Funding did not record any goodwill impairments.

(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 $— million as of December 31, 2021 and 2020, 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, 2021 and 2020.

(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 2022 and has a variable interest rate based on the Eurodollar rate plus a spread. As of December 31, 2021 and 2020, there were no borrowings outstanding under this credit facility. As of December 31, 2021, 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, 2021 and 2020.

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 $5.6 billion as of December 31, 2021.

As of December 31, 2021, 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 benefit consists of the following for the years ended December 31 (in millions):

	2021	2020	2019
Current:			
Federal	$ (739)	$ (689)	$ (480)
State	(94)	(96)	(49)
	(833)	(785)	(529)
Deferred:			
Federal	189	204	164
State	(35)	8	(11)
	154	212	153
Investment tax credits	(1)	(1)	(1)
Total	$ (680)	$ (574)	$ (377)

A reconciliation of the federal statutory income tax rate to MidAmerican Funding's effective income tax rate applicable to income before income tax benefit is as follows for the years ended December 31:

	2021	2020	2019
Federal statutory income tax rate	21 %	21 %	21 %
Income tax credits	(283)	(209)	(94)
State income tax, net of federal income tax benefit	(50)	(29)	(12)
Effects of ratemaking	(21)	(17)	(8)
Other, net	(2)	(1)	—
Effective income tax rate	(335)%	(235)%	(93)%

Income tax credits relate primarily to production tax credits ("PTC") earned by MidAmerican Energy'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.

MidAmerican Funding's net deferred income tax liability consists of the following as of December 31 (in millions):

	2021	2020
Deferred income tax assets:		
Regulatory liabilities	$ 240	$ 288
Asset retirement obligations	220	229
State carryforwards	55	52
Employee benefits	26	43
Other	30	40
Total deferred income tax assets	571	652
Valuation allowances	(1)	(25)
Total deferred income tax assets, net	570	627
Deferred income tax liabilities:		
Depreciable property	(3,843)	(3,583)
Regulatory assets	(112)	(97)
Other	(2)	1
Total deferred income tax liabilities	(3,957)	(3,679)
Net deferred income tax liability	$ (3,387)	$ (3,052)

As of December 31, 2021, MidAmerican Funding's state tax carryforwards, principally related to $823 million of net operating losses, expire at various intervals between 2022 and 2040.

The United States Internal Revenue Service has closed or effectively settled its examination MidAmerican Funding's income tax returns through December 31, 2013. The statute of limitations for MidAmerican Funding's state income tax returns have expired through December 31, 2011, for Michigan and Nebraska, and through December 31, 2017, for Illinois, Indiana, Iowa, Kansas and Missouri, except for the impact of any federal audit adjustments. The statute of limitations expiring 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):

	2021	2020
Beginning balance	$ 8	$ 8
Additions based on tax positions related to the current year	16	4
Reductions based on tax positions related to the current year	(11)	(3)
Reductions for tax positions of prior years	—	(1)
Ending balance	$ 13	$ 8

As of December 31, 2021, MidAmerican Funding had unrecognized tax benefits totaling $33 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):

	2021	2020	2019
Pension costs	$ 21	$ 7	$ 4
Other postretirement costs	2	(3)	(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):

	2021		2020	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 7,961	$ 9,350	$ 7,450	$ 9,466

(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. Plaintiffs occasionally seek punitive or exemplary damages. 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. Additionally, MidAmerican Funding had $— million, $8 million and $2 million of other revenue from contracts with customers for the year ended December 31, 2021, 2020 and 2019, respectively.

(15) 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):

	2021	2020	2019
Non-service cost components of postretirement employee benefit plans	$ 26	$ 24	$ 17
Corporate-owned life insurance income	21	16	24
Gains on disposition of assets	—	6	—
Interest income and other, net	7	6	11
Total	$ 54	$ 52	$ 52

(16) Supplemental Cash Flow Information

Cash equivalents consist of funds invested in money market mutual funds, United States 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 as of December 31, 2021 and 2020 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, 2021 and 2020 as presented in 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,	
	2021	2020
Cash and cash equivalents	$ 233	$ 39
Restricted cash and cash equivalents in other current assets	7	7
Total cash and cash equivalents and restricted cash and cash equivalents	$ 240	$ 46

The summary of supplemental cash flow information as of and for the years ending December 31 is as follows (in millions):

	2021	2020	2019
Supplemental disclosure of cash flow information:			
Interest paid, net of amounts capitalized	$ 296	$ 302	$ 245
Income taxes received, net	$ 751	$ 715	$ 456
Supplemental disclosure of non-cash investing and financing transactions:			
Accounts payable related to utility plant additions	$ 257	$ 227	$ 337
Distribution of corporate aircraft to parent	$ —	$ —	$ 8

(17) 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 $65 million, $46 million and $41 million for 2021, 2020 and 2019, respectively. Additionally, in 2019, recorded a noncash dividend of $8 million for the transfer to BHE of corporate aircraft owned by MHC.

MidAmerican Funding reimbursed BHE in the amount of $72 million, $15 million and $14 million in 2021, 2020 and 2019, respectively, for its share of corporate expenses.

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 $132 million, $129 million and $139 million in 2021, 2020 and 2019, respectively. Additionally, in 2020, MidAmerican Energy paid $7 million to BHE Renewables, LLC, a wholly owned subsidiary of BHE, for the purchase of wind turbine components.

MHC has a $300 million revolving credit arrangement carrying interest at the 30-day London Interbank Offered Rate ("LIBOR") rate plus a spread to borrow from BHE. Outstanding balances are unsecured and due on demand. The outstanding balance was $189 million at an interest rate of 0.353% as of December 31, 2021, and $177 million at an interest rate of 0.397% as of December 31, 2020, and is reflected as note payable to affiliate on the Consolidated Balance Sheet.

BHE has a $100 million revolving credit arrangement, carrying interest at the 30-day LIBOR rate plus a spread to borrow from MHC. Outstanding balances are unsecured and due on demand. There were no borrowings outstanding throughout 2021 and 2020.

MidAmerican Funding had accounts receivable from affiliates of $11 million and $13 million as of December 31, 2021 and 2020, respectively, that are included in other current assets on the Consolidated Balance Sheets. MidAmerican Funding also had accounts payable to affiliates of $17 million and $13 million as of December 31, 2021 and 2020, 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 United States federal income tax return. For current federal and state income taxes, MidAmerican Funding had a receivable from BHE of $80 million as of December 31, 2021, and a payable to BHE of $14 million as of December 31, 2020. MidAmerican Funding received net cash payments for federal and state income taxes from BHE totaling $751 million, $715 million and $456 million for the years ended December 31, 2021, 2020 and 2019, 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 $124 million and $146 million as of December 31, 2021 and 2020, respectively, and are included in other assets on the Consolidated Balance Sheets. Similar amounts payable to affiliates totaled $63 million and $49 million as of December 31, 2021 and 2020, 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+.

(18) 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 (benefit) expense 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,		
	2021	2020	2019
Operating revenue:			
Regulated electric	$ 2,529	$ 2,139	$ 2,237
Regulated natural gas	1,003	573	660
Other	15	16	30
Total operating revenue	$ 3,547	$ 2,728	$ 2,927
Depreciation and amortization:			
Regulated electric	$ 861	$ 667	$ 593
Regulated natural gas	53	49	46
Total depreciation and amortization	$ 914	$ 716	$ 639
Operating income:			
Regulated electric	$ 358	$ 384	$ 473
Regulated natural gas	58	64	71
Other	—	6	5
Total operating income	$ 416	$ 454	$ 549
Interest expense:			
Regulated electric	$ 279	$ 281	$ 259
Regulated natural gas	23	23	22
Other	17	18	21
Total interest expense	$ 319	$ 322	$ 302
Income tax (benefit) expense:			
Regulated electric	$ (677)	$ (584)	$ (384)
Regulated natural gas	3	14	12
Other	(6)	(4)	(5)
Total income tax (benefit) expense	$ (680)	$ (574)	$ (377)
Net income:			
Regulated electric	$ 844	$ 780	$ 739
Regulated natural gas	50	45	52
Other	(11)	(7)	(10)
Net income	$ 883	$ 818	$ 781

	Years Ended December 31,		
	2021	2020	2019
Capital expenditures:			
Regulated electric	$ 1,806	$ 1,704	$ 2,684
Regulated natural gas	106	132	126
Total capital expenditures	$ 1,912	$ 1,836	$ 2,810

	As of December 31,		
	2021	2020	2019
Total assets:			
Regulated electric	$ 22,576	$ 21,083	$ 20,284
Regulated natural gas	1,950	1,623	1,547
Other	5	5	9
Total assets	$ 24,531	$ 22,711	$ 21,840

Goodwill by reportable segment as of December 31, 2021 and 2020, 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, 2021 was $303 million, an increase of $8 million, or 3%, compared to 2020, primarily due to $92 million of lower operations and maintenance expenses, primarily due to lower net regulatory instructed deferrals and amortizations, lower earnings sharing and lower plant operations and maintenance expenses, $36 million of lower income tax expense primarily due to the recognition of amortization of excess deferred income taxes following regulatory approval effective January 2021, $10 million of higher interest and dividend income, mainly from carrying charges on regulatory balances, $9 million of lower interest expense and $9 million of higher other, net. These increases are offset by $102 million of lower utility margin, primarily due to lower retail rates from the 2020 regulatory rate review with new rates effective January 2021, lower revenue recognized due to a favorable regulatory decision in 2020 and an adjustment to regulatory-related revenue deferrals, partially offset by an increase in the average number of customers and higher transmission revenue, and $45 million of higher depreciation and amortization, mainly due to regulatory amortizations approved in the 2020 regulatory rate review effective January 2021 and higher plant placed in-service.

Net income for the year ended December 31, 2020 was $295 million, an increase of $31 million, or 12%, compared to 2019, primarily due to $97 million of higher utility margin mainly due to higher retail customer volumes, revenue recognized due to a favorable regulatory decision and price impacts from changes in sales mix. Retail customer volumes, including distribution only service customers, increased 2.0%, primarily due to the favorable impact of weather, largely offset by the impacts of COVID-19, which resulted in lower industrial, distribution only service and commercial customer usage and higher residential customer usage. The increase in net income is offset by $69 million of higher operations and maintenance expenses primarily due to a higher accrual for earnings sharing of $43 million and higher regulatory-directed debits of $27 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, 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):

	2021	2020	Change		2020	2019	Change	
Utility margin:								
Operating revenue	$ 2,139	$ 1,998	$ 141	7 %	$ 1,998	$ 2,148	$ (150)	(7)%
Cost of fuel and energy	939	816	123	15	816	943	(127)	(13)
Utility margin	1,200	1,182	18	2	1,182	1,205	(23)	(2)
Operations and maintenance	301	299	2	1	299	324	(25)	(8)
Depreciation and amortization	406	361	45	12	361	357	4	1
Property and other taxes	48	47	1	2	47	45	2	4
Operating income	$ 445	$ 475	$ (30)	(6)%	$ 475	$ 479	$ (4)	(1)%

Utility Margin

A comparison of key operating results related to utility margin is as follows for the years ended December 31:

	2021	2020	Change		2020	2019	Change	
Utility margin (in millions):								
Operating revenue	$ 2,139	$ 1,998	$ 141	7 %	$ 1,998	$ 2,148	$ (150)	(7)%
Cost of fuel and energy	939	816	123	15	816	943	(127)	(13)
Utility margin	$ 1,200	$ 1,182	$ 18	2 %	$ 1,182	$ 1,205	$ (23)	(2)%
Sales (GWhs):								
Residential	10,415	10,477	(62)	(1)%	10,477	9,311	1,166	13 %
Commercial	4,838	4,591	247	5	4,591	4,657	(66)	(1)
Industrial	5,270	4,881	389	8	4,881	5,344	(463)	(9)
Other	198	195	3	2	195	193	2	1
Total fully bundled[1]	20,721	20,144	577	3	20,144	19,505	639	3
Distribution only service	2,646	2,425	221	9	2,425	2,613	(188)	(7)
Total retail	23,367	22,569	798	4	22,569	22,118	451	2
Wholesale	356	374	(18)	(5)	374	527	(153)	(29)
Total GWhs sold	23,723	22,943	780	3 %	22,943	22,645	298	1 %
Average number of retail customers (in thousands)	985	968	17	2 %	968	951	17	2 %
Average revenue per MWh:								
Retail - fully bundled[1]	$ 98.62	$ 94.83	$ 3.79	4 %	$ 94.83	$105.88	$ (11.05)	(10)%
Wholesale	$ 60.69	$ 42.83	$ 17.86	42 %	$ 42.83	$ 35.87	$ 6.96	19 %
Heating degree days	1,613	1,753	(140)	(8)%	1,753	1,875	(122)	(7)%
Cooling degree days	4,109	4,236	(127)	(3)%	4,236	3,648	588	16 %
Sources of energy (GWhs)[2][3]:								
Natural gas	13,655	13,545	110	1 %	13,545	13,161	384	3 %
Coal	—	—	—	—	—	1,059	(1,059)	(100)
Renewables	65	66	(1)	(2)	66	61	5	8
Total energy generated	13,720	13,611	109	1	13,611	14,281	(670)	(5)
Energy purchased	7,778	7,044	734	10	7,044	6,167	877	14
Total	21,498	20,655	843	4 %	20,655	20,448	207	1 %
Average cost of energy per MWh[4]:								
Energy generated	$ 24.41	$ 16.58	$ 7.83	47 %	$ 16.58	$ 26.95	$ (10.37)	(38)%
Energy purchased	$ 77.64	$ 83.74	$ (6.10)	(7)%	$ 83.74	$ 90.50	$ (6.75)	(7)%

(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 -, - and 153 GWhs of coal and 1,389, 1,614 and 1,756 GWhs of natural gas generated energy that is purchased at cost by related parties for the years ended December 31, 2021, 2020 and 2019, 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, 2021 Compared to Year Ended December 31, 2020

Utility margin increased $18 million, or 2%, for 2021 compared to 2020 primarily due to:

- the $120 million one-time bill credit returned to customers in 2020 as a result of the Nevada Power regulatory rate review stipulation ("$120 million bill credit") (offset in operations and maintenance expense and income tax expense) and
- $5 million of higher transmission revenue.

The increase in utility margin was offset by:

- $66 million of lower retail electric utility margin primarily due to lower retail rates due to the 2020 regulatory rate review with new rates effective January 2021, offset by higher retail customer volumes. Retail customer volumes, including distribution only service customers, increased 3.5% primarily due to an increase in the average number of customers and favorable changes in customer usage patterns, offset by the unfavorable impact of weather;
- $21 million of lower revenue recognized due to a favorable regulatory decision in 2020;
- $10 million due to lower energy efficiency program costs (offset in operations and maintenance expense);
- $6 million due to an adjustment to regulatory-related revenue deferrals; and
- $4 million due to a regulatory amortization of an impact fee that ended December 2020.

Operations and maintenance increased $2 million, or 1%, for 2021 compared to 2020 primarily due to regulatory liability amortization in 2020 to satisfy a portion of the $120 million bill credit of $94 million (offset in operating revenue), partially offset by lower net regulatory instructed deferrals and amortizations of $46 million, mainly relating to deferrals in 2020 of the non-labor cost savings from the Navajo generating station retirement which was approved for amortization in the 2020 regulatory rate review with new rates effective January 2021, and timing of the regulatory impacts for the ON Line lease cost reallocation, lower earnings sharing, lower energy efficiency program costs (offset in operating revenue) and lower plant operations and maintenance expenses.

Depreciation and amortization increased $45 million, or 12%, for 2021 compared to 2020 primarily due to regulatory amortizations approved in the 2020 regulatory rate review effective January 2021 and higher plant placed in-service.

Interest expense decreased $9 million, or 6%, for 2021 compared to 2020 primarily due to lower carrying charges on regulatory balances of $6 million and lower interest expense on long-term debt.

Interest and dividend income increased $10 million for 2021 compared to 2020 primarily due to higher interest income, mainly from carrying charges on regulatory balances.

Other, net increased $9 million, for 2021 compared to 2020 primarily due to lower pension expense of $6 million and higher cash surrender value of corporate-owned life insurance policies.

Income tax expense decreased $10 million, or 21%, for 2021 compared to 2020. The effective tax rate was 11% in 2021 and 14% in 2020 and decreased primarily due to the recognition of amortization of excess deferred income taxes following regulatory approval effective January 2021, partially offset by the one-time recognition in 2020 of amortization of excess deferred income taxes to satisfy a portion of the $120 million bill credit (offset in operating revenue).

Year Ended December 31, 2020 Compared to Year Ended December 31, 2019

Utility margin decreased $23 million for 2020 compared to 2019 due to:

- the $120 million bill credit (offset in operations and maintenance expense and income tax expense) and
- $5 million of higher revenue reductions related to customer service agreements.

The decrease in utility margin was partially offset by:

- $45 million in higher residential customer volumes from the favorable impact of weather;
- $21 million of revenue recognized due to a favorable regulatory decision;
- $16 million due to price impacts from changes in sales mix. Retail customer volumes, including distribution-only service customers, increased 2.0% primarily due to the favorable impacts of weather, offset by the impacts of COVID-19, which resulted in lower industrial, commercial and distribution-only service customer usage and higher residential customer usage;
- $8 million due to higher energy efficiency program costs (offset in operations and maintenance expense);
- $7 million of higher transmission and wholesale revenue; and
- $5 million of customer growth mainly from residential customers.

Operations and maintenance decreased $25 million, or 8%, for 2020 compared to 2019 primarily due to higher regulatory liability amortization to satisfy a portion of the $120 million bill credit of $94 million (offset in operating revenue) and lower plant operation and maintenance costs, partially offset by a higher accrual for earnings sharing of $43 million, higher regulatory-directed debits of $27 million, relating to the deferral of the non-labor cost savings from the Navajo generating station retirement in 2019, the deferral of costs for the ON Line lease to be returned to customers due to the regulatory-directed reallocation of costs between Nevada Power and Sierra Pacific (offset in depreciation and amortization and other income (expense)) and costs recognized for the $120 million bill credit, and higher energy efficiency program costs (offset in operating revenue).

Depreciation and amortization increased $4 million, or 1%, for 2020 compared to 2019 primarily due to higher plant placed in-service, offset by lower depreciation expense on the ON Line lease due to the regulatory-directed reallocation of costs between Nevada Power and Sierra Pacific (offset in operations and maintenance).

Property and other taxes increased $2 million, or 4%, for 2020 compared to 2019 primarily due to a decrease in available abatements and franchise tax audit assessments.

Other income (expense) is favorable $9 million, or 6%, for 2020 compared to 2019 primarily due to lower interest expense on the ON Line lease due to the regulatory-directed reallocation of costs between Nevada Power and Sierra Pacific (offset in operations and maintenance expense), lower pension costs and lower interest expense on long-term debt due to lower interest rates, offset by lower other income due to a licensing agreement with a third party in 2019 and lower cash surrender value of corporate-owned life insurance policies.

Income tax expense decreased $26 million, or 36%, for 2020 compared to 2019. The effective tax rate was 14% in 2020 and 22% in 2019 and decreased due to the one-time recognition of amortization of excess deferred income taxes to satisfy a portion of the $120 million bill credit (offset in operating revenue).

Liquidity and Capital Resources

As of December 31, 2021, Nevada Power's total net liquidity was $253 million as follows (in millions):

Cash and cash equivalents	$ 33
Credit facilities[(1)]	400
Less -	
Short-term debt	(180)
Net credit facilities	220
Total net liquidity	$ 253
Credit facilities:	
Maturity dates	2024

(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, 2021 and 2020 were $505 million and $467 million, respectively. The change was primarily due to higher collections from customers, timing of payments for operating costs, increased collections of customer advances and lower inventory purchases, partially offset by the timing of payments for fuel and energy costs and higher payments for income taxes.

Net cash flows from operating activities for the years ended December 31, 2020 and 2019 were $467 million and $701 million, respectively. The change was primarily due to lower collections from customers, mainly due to the $120 million bill credit, higher payments for fuel and energy costs, the timing of payments for operating costs, lower proceeds from a licensing agreement with a third party in 2019 and decreased collections of customer advances, partially offset by lower payments for income taxes and lower interest payments for long-term debt.

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, 2021 and 2020 were $(447) million and $(429) 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, 2020 and 2019 were $(429) million and $(407) million, respectively. The change was primarily due to increased capital expenditures, partially offset by higher proceeds from sale of assets primarily related to the regulatory-directed reallocation of ON Line assets between Nevada Power and Sierra Pacific. 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, 2021 and 2020 were $(49) million and $(27) million, respectively. The change was primarily due to lower proceeds from the issuance of long-term debt and higher dividends paid to NV Energy, Inc., partially offset by lower repayments of long-term debt and higher net proceeds from short-term debt.

Net cash flows from financing activities for the years ended December 31, 2020 and 2019 were $(27) million and $(390) million, respectively. The change was primarily due to greater proceeds from the issuance of long-term debt and lower dividends paid to NV Energy, Inc., partially offset by higher repayments of long-term debt.

Ability to Issue Debt

Nevada Power currently has an effective automatic registration statement with the SEC to issue an indeterminate amount of long-term debt securities through October 15, 2022. Additionally, Nevada Power's ability to issue debt is primarily impacted by its financing authority from the PUCN. As of December 31, 2021, 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 $400 million secured credit facility) does not exceed $3.2 billion 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, 2021. 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.

In January 2022, the PUCN approved Nevada Power's request to increase its financing authority for debt securities to not exceed $3.8 billion as measured at the end of each calendar quarter. Additionally, the PUCN authorized Nevada Power to issue common and preferred stock so long as the total amounts outstanding do not exceed $4.1 billion and $800 million, respectively, at the end of each calendar quarter.

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, 2021, $9.4 billion of Nevada Power's assets were pledged. Nevada Power had the capacity to issue $3.7 billion of additional general and refunding mortgage securities as of December 31, 2021, determined on the basis of 70% of net utility property additions. Property additions include plant-in-service and specific assets in construction work-in-progress. The amount of bond capacity listed above does not include eligible property in construction work-in-progress. Nevada Power also has the ability to release property from the lien of Nevada Power's indenture on the basis of net property additions, cash or retired bonds. To the extent Nevada Power releases property from the lien of Nevada Power's indenture, it will reduce the amount of securities issuable under the indenture.

Long-Term Debt

In January 2022, Nevada Power entered into a $300 million secured delayed draw term loan facility maturing in January 2024. Amounts borrowed under the facility bear interest at variable rates based on the Secured Overnight Financing Rate or a base rate, at Nevada Power's option, plus a pricing margin. In January 2022, Nevada Power borrowed $200 million under the facility at an initial interest rate of 0.55%. Nevada Power may draw all or none of the remaining unused commitment through June 2022. Nevada Power used the proceeds to repay amounts outstanding under its existing secured credit facility and for general corporate purposes.

<u>Future Uses of Cash</u>

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		
	2019	**2020**	**2021**	**2022**	**2023**	**2024**
Electric distribution	$ 209	$ 232	$ 184	$ 193	$ 184	$ 181
Electric transmission	24	35	57	169	206	432
Solar generation	—	—	8	95	568	602
Other	171	188	200	576	276	163
Total	$ 404	$ 455	$ 449	$ 1,033	$ 1,234	$ 1,378

Nevada Power received PUCN approval through its recent IRP filings for an increase in solar generation and electric transmission and has included estimates from its IRP filings in its forecast capital expenditures for 2022 through 2024. These estimates are likely to change as a result of the RFP process. 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. In this project, the company has received approval from the PUCN to build a 350-mile, 525-kV transmission line, known as Greenlink West, connecting the Ft. Churchill substation to the Northwest substation to the Harry Allen substation; a 235-mile, 525-kV transmission line, known as Greenlink North, connecting the new Ft. Churchill substation to the Robinson Summit substation; a 46-mile, 345-kV transmission line from the new Ft. Churchill substation to the Mira Loma substations; and a 38-mile, 345-kV transmission line from the new Ft. Churchill substation to the Robinson Summit substations. Operating expenditures consist of routine expenditures for transmission and other infrastructure needed to serve existing and expected demand.
- Solar generation includes growth projects consisting of three solar photovoltaic facilities. The first project is 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 the end of 2023. The second project is a 250-MW solar photovoltaic facility with an additional 200 MWs of co-located battery storage that will be developed in Humboldt County, Nevada. Commercial operation is expected by the end of 2023. The final project is a 350-MW solar photovoltaic facility with an additional 280 MWs of co-located battery storage that will be developed in Humboldt County, Nevada. Commercial operation is expected by the end of 2024. The facilities located in Humboldt County will be jointly owned and operated by Nevada Power and Sierra Pacific.
- Other includes both growth projects and operating expenditures consisting of turbine upgrades at several generating facilities, routine expenditures for generation, other operating projects and other infrastructure needed to serve existing and expected demand.

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 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 $1.8 billion on long-term debt, including $115 million due in 2022.

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 climate change, RPS, air and water quality, emissions performance standards, coal combustion byproduct disposal, hazardous and solid waste disposal, protected species 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 "Liquidity and Capital Resources" for discussion of Nevada Power's forecasted environmental-related capital expenditures.

Refer to "Environmental Laws and Regulations" in Item 1 of this Form 10-K for additional information 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, 2021, 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, 2021, Nevada Power would have been required to post $113 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 structure administered by the PUCN and the FERC. Under this rate 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.

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 the 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 billion and total regulatory liabilities were $1.1 billion as of December 31, 2021. 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 the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value and any resulting impairment loss is reflected on the Consolidated Statements of Operations. As substantially all property, plant and equipment was used in regulated businesses as of December 31, 2021, 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 the asset that are used in the impairment analysis requires judgment regarding what Nevada Power would expect to recover from the future use of the asset. Changes in judgment that could significantly alter the calculation of the fair value or the recoverable amount of the asset may result from significant changes in the regulatory environment, the business climate, management's plans, legal factors, market price of the asset, the use of the asset or 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, if any, 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 benefits and expense related to the federal tax rate change from 35% to 21% as a result of 2017 Tax Reform, certain property related basis differences and other various differences on to its customers. As of December 31, 2021, these amounts were recognized as a net regulatory liability of $603 million and will be included in regulated rates when the temporary differences reverse.

Revenue Recognition - Unbilled Revenue

Revenue is recognized as electricity is delivered or services are provided. The determination of customer billings is based on a systematic reading of meters. At the end of each month, energy provided to customers since their last billing is estimated, and the corresponding unbilled revenue is recorded. Unbilled revenue was $107 million as of December 31, 2021. 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. Estimates are reversed in the following month when actual revenue is recorded.

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, 2021:			
Total commodity derivative contracts	$ (113)	$ (93)	$ (133)
As of December 31, 2020:			
Total commodity derivative contracts	$ 15	$ 19	$ 11

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, 2021 and 2020, a net regulatory asset of $113 million and a net regulatory liability of $15 million, respectively, was recorded related to the net derivative liability of $113 million and net derivative asset of $15 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, 2021 and 2020, Nevada Power had short-term variable-rate obligations totaling $180 million and $— 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, 2021 and 2020.

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, 2021, 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	335
Consolidated Balance Sheets	337
Consolidated Statements of Operations	338
Consolidated Statements of Changes in Shareholder's Equity	339
Consolidated Statements of Cash Flows	340
Notes to Consolidated Financial Statements	341

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, 2021 and 2020, 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, 2021, 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, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021, 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 — Impact of Rate Regulation on the Financial Statements — Refer to Notes 2 and 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 it meets 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 impacts multiple financial statement line items and disclosures, such as property, plant, and equipment, net; regulatory assets and liabilities; deferred income taxes; operating revenue; operations and maintenance expense; depreciation and amortization expense, and income tax expense.

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 impact 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 impact of rate regulation as a critical audit matter due to the significant judgments made by management to support its assertions about impacted account balances and disclosures and the high degree of subjectivity involved in assessing the impact of future 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 future 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 impacts of rate regulation, including the balances recorded and regulatory developments.
- We read relevant regulatory orders issued by the Commissions, regulatory statutes, interpretations, procedural memorandums, filings made by interveners, and other publicly available information 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 evaluated the external information and compared to management's recorded regulatory asset and liability balances for completeness.
- For regulatory matters in process, we inspected Nevada Power's filings with the Commissions and the filings with the Commissions by intervenors that may impact Nevada Power's future rates, for any evidence that might contradict management's assertions.
- 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 25, 2022

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,	
	2021	**2020**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 33	$ 25
Trade receivables, net	227	234
Inventories	64	69
Derivative contracts	4	26
Regulatory assets	291	48
Prepayments	33	38
Other current assets	49	26
Total current assets	701	466
Property, plant and equipment, net	6,891	6,701
Finance lease right of use assets, net	326	351
Regulatory assets	728	746
Other assets	106	72
Total assets	$ 8,752	$ 8,336
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities:		
Accounts payable	$ 242	$ 181
Accrued interest	32	32
Accrued property, income and other taxes	29	25
Short-term debt	180	—
Current portion of finance lease obligations	26	27
Regulatory liabilities	49	50
Customer deposits	44	47
Asset retirement obligation	19	25
Derivative contracts	55	4
Other current liabilities	17	18
Total current liabilities	693	409
Long-term debt	2,499	2,496
Finance lease obligations	310	334
Regulatory liabilities	1,100	1,163
Deferred income taxes	782	738
Other long-term liabilities	338	257
Total liabilities	5,722	5,397
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	2,308	2,308
Retained earnings	724	634
Accumulated other comprehensive loss, net	(2)	(3)
Total shareholder's equity	3,030	2,939
Total liabilities and shareholder's equity	$ 8,752	$ 8,336

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,		
	2021	**2020**	**2019**
Operating revenue	$ 2,139	$ 1,998	$ 2,148
Operating expenses:			
Cost of fuel and energy	939	816	943
Operations and maintenance	301	299	324
Depreciation and amortization	406	361	357
Property and other taxes	48	47	45
Total operating expenses	1,694	1,523	1,669
Operating income	445	475	479
Other income (expense):			
Interest expense	(153)	(162)	(171)
Allowance for borrowed funds	3	3	3
Allowance for equity funds	7	7	5
Interest and dividend income	20	10	13
Other, net	18	9	8
Total other income (expense)	(105)	(133)	(142)
Income before income tax expense	340	342	337
Income tax expense	37	47	73
Net income	$ 303	$ 295	$ 264

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, 2018	1,000	$ —	$ 2,308	$ 600	$ (4)	$ 2,904
Net income	—	—	—	264	—	264
Dividends declared	—	—	—	(371)	—	(371)
Balance, December 31, 2019	1,000	—	2,308	493	(4)	2,797
Net income	—	—	—	295	—	295
Dividends declared	—	—	—	(155)	—	(155)
Other equity transactions	—	—	—	1	1	2
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

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,		
	2021	**2020**	**2019**
Cash flows from operating activities:			
Net income	$ 303	$ 295	$ 264
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	406	361	357
Allowance for equity funds	(7)	(7)	(5)
Changes in regulatory assets and liabilities	(19)	(42)	27
Deferred income taxes and amortization of investment tax credits	—	(10)	(32)
Deferred energy	(245)	(44)	51
Amortization of deferred energy	11	(41)	43
Other, net	—	2	(5)
Changes in other operating assets and liabilities:			
Trade receivables and other assets	6	45	19
Inventories	5	(7)	1
Accrued property, income and other taxes	(18)	5	(13)
Accounts payable and other liabilities	63	(90)	(6)
Net cash flows from operating activities	505	467	701
Cash flows from investing activities:			
Capital expenditures	(449)	(455)	(409)
Proceeds from sale of assets	—	26	2
Other, net	2	—	—
Net cash flows from investing activities	(447)	(429)	(407)
Cash flows from financing activities:			
Proceeds from long-term debt	—	718	495
Repayments of long-term debt	—	(575)	(500)
Net proceeds from short-term debt	180	—	—
Dividends paid	(213)	(155)	(371)
Other, net	(16)	(15)	(14)
Net cash flows from financing activities	(49)	(27)	(390)
Net change in cash and cash equivalents and restricted cash and cash equivalents	9	11	(96)
Cash and cash equivalents and restricted cash and cash equivalents at beginning of period	36	25	121
Cash and cash equivalents and restricted cash and cash equivalents at end of period	$ 45	$ 36	$ 25

The accompanying notes are an integral part of these 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 United States 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, 2021, 2020 and 2019.

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 in 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 Equivalents and Restricted Cash and Investments

Cash equivalents consist of funds invested in money market mutual funds, United States 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 amounts are included in other current assets and other assets on the Consolidated Balance Sheets.

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):

	2021	2020	2019
Beginning balance	$ 19	$ 15	$ 16
Charged to operating costs and expenses, net	13	13	12
Write-offs, net	(14)	(9)	(13)
Ending balance	$ 18	$ 19	$ 15

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 $64 million and $69 million as of December 31, 2021 and 2020. 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 2021 and 2020 was 7.14% and 7.43%, 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 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 the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value and any resulting impairment loss is reflected on the Consolidated Statements of Operations. As substantially all property, plant and equipment was used in regulated businesses as of December 31, 2021, 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.

Income Taxes

Berkshire Hathaway includes Nevada Power in its consolidated United States federal income tax return. Consistent with established regulatory practice, Nevada Power's provision for income taxes has been computed on a separate return 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 that are associated with components of other comprehensive income ("OCI") are charged or credited directly to OCI. Changes in deferred income tax assets and liabilities that are 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 generally 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.

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, 2021 and 2020, trade receivables, net on the Consolidated Balance Sheets relate substantially to Customer Revenue, including unbilled revenue of $107 million and $104 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 $6 million and $8 million as of December 31, 2021 and 2020, 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 on a straight-line basis.

Segment Information

Nevada Power currently has one segment, which includes its regulated electric utility operations.

(3) Property, Plant and Equipment, Net

Property, plant and equipment, net consists of the following as of December 31 (in millions):

	Depreciable Life	2021	2020
Utility plant:			
Generation	30 - 55 years	$ 3,793	$ 3,690
Transmission	45 - 70 years	1,503	1,468
Distribution	20 - 65 years	3,920	3,771
General and intangible plant	5 - 65 years	836	791
Utility plant		10,052	9,720
Accumulated depreciation and amortization		(3,406)	(3,162)
Utility plant, net		6,646	6,558
Other non-regulated, net of accumulated depreciation and amortization	45 years	1	1
Plant, net		6,647	6,559
Construction work-in-progress		244	142
Property, plant and equipment, net		$ 6,891	$ 6,701

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, 2021, 2020 and 2019 was 3.2%, 3.1%, and 3.3%, 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 2017.

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, 2021 (dollars in millions):

	Nevada Power's Share	Utility Plant	Accumulated Depreciation	Construction Work-in-Progress
Navajo Generating Station(1)	11 %	$ 5	$ 5	$ —
ON Line Transmission Line	19	120	23	1
Other transmission facilities	Various	61	32	—
Total		$ 186	$ 60	$ 1

(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):

	2021	2020
Right-of-use assets:		
Operating leases	$ 10	$ 12
Finance leases	326	351
Total right-of-use assets	$ 336	$ 363
Lease liabilities:		
Operating leases	$ 13	$ 15
Finance leases	336	361
Total lease liabilities	$ 349	$ 376

The following table summarizes Nevada Power's lease costs for the years ended December 31 (in millions):

	2021	2020	2019
Variable	$ 449	$ 434	$ 434
Operating	2	3	3
Finance:			
Amortization	13	12	13
Interest	28	29	37
Total lease costs	$ 492	$ 478	$ 487
Weighted-average remaining lease term (years):			
Operating leases	5.7	6.5	7.5
Finance leases	28.7	28.7	30.6
Weighted-average discount rate:			
Operating leases	4.5 %	4.5 %	4.5 %
Finance leases	8.6 %	8.6 %	8.7 %

The following table summarizes Nevada Power's supplemental cash flow information relating to leases for the years ended December 31 (in millions):

	2021	2020	2019
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	(29)	(34)	(37)
Financing cash flows from finance leases	(16)	(15)	(14)
Right-of-use assets obtained in exchange for lease liabilities:			
Operating leases	$ —	$ 1	$ —
Finance leases	1	9	9

Nevada Power has the following remaining lease commitments as of December 31, 2021 (in millions):

	Operating	Finance	Total
2022	$ 3	$ 54	$ 57
2023	2	44	46
2024	3	44	47
2025	2	43	45
2026	3	43	46
Thereafter	2	448	450
Total undiscounted lease payments	15	676	691
Less - amounts representing interest	(2)	(340)	(342)
Lease liabilities	$ 13	$ 336	$ 349

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, previously split 95% for Nevada Power and 5% for Sierra Pacific. In December 2019, the PUCN ordered the Nevada Utilities to complete the necessary procedures to change the ownership split to 75% for Nevada Power and 25% for Sierra Pacific, effective January 1, 2020. In August 2020, the FERC approved the amended agreement between the Nevada Utilities and Great Basin Transmission, LLC that reallocated the PUCN-approved ownership percentage change from Nevada Power to Sierra Pacific. The term of the lease is 41 years with the agreement ending December 31, 2054. Total ON Line finance lease obligations of $286 million and $295 million were included on the Consolidated Balance Sheets as of December 31, 2021 and 2020, 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	2021	2020
Deferred energy costs	1 year	$ 273	$ 39
Decommissioning costs	2 years	169	230
Unrealized loss on regulated derivative contracts	1 year	117	11
Merger costs from 1999 merger	23 years	110	115
Deferred operating costs	12 years	93	119
Asset retirement obligations	6 years	73	70
ON Line deferrals	32 years	42	43
Legacy meters	11 years	41	45
Employee benefit plans[(1)]	8 years	11	50
Other	Various	90	72
Total regulatory assets		$ 1,019	$ 794
Reflected as:			
Current assets		$ 291	$ 48
Noncurrent assets		728	746
Total regulatory assets		$ 1,019	$ 794

(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.

Nevada Power had regulatory assets not earning a return on investment of $371 million and $288 million as of December 31, 2021 and 2020, respectively. The regulatory assets not earning a return on investment primarily consist of merger costs from the 1999 merger, AROs, deferred operating costs, a portion of the employee benefit plans, losses on reacquired debt and deferred energy costs.

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	2021	2020
Deferred income taxes[(1)]	Various	$ 603	$ 647
Cost of removal[(2)]	31 years	348	340
Other	Various	198	226
Total regulatory liabilities		$ 1,149	$ 1,213
Reflected as:			
Current liabilities		$ 49	$ 50
Noncurrent liabilities		1,100	1,163
Total regulatory liabilities		$ 1,149	$ 1,213

(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.

Natural Disaster Protection Plan ("NDPP")

In March 2021, Nevada Power filed an application seeking recovery of the 2020 expenditures, approval for an update to the initial NDPP that was ordered by the PUCN and filed their first amendment to the 2020 NDPP. A hearing related to the application for approval of the first amendment to the 2020 NDPP was held in June 2021. Nevada Power filed a partial-party stipulation resolving all issues. One of the intervening parties filed an opposition to the partial-party stipulation and other intervenors filed legal briefs. The partial-party stipulation was approved by the PUCN in June 2021 with the lone dissenting party retaining the right to argue a single issue in future proceedings with the primary issue being a single statewide rate as a cost recovery mechanism. In July 2021, a hearing was held on the cost recovery of 2020 expenditures. In September 2021, the PUCN issued an order, approving the recovery of the 2020 expenditures with adjustments for vegetation management, inspections and corrections and rate structure. Certain vegetation management expenditures were to be removed from the NDPP rate and deemed to be recovered through the general three-year regulatory rate review process. A portion of the inspections and corrections were deferred to seek recovery in a future NDPP rate filing. Lastly, the order approved cost recovery based on a hybrid rate calculation comprised of a statewide rate component for operating costs and a service territory specific rate component for capital costs. In September 2021, Nevada Power and one of the intervening parties filed petitions for reconsideration that were granted by the PUCN. In January 2022, the PUCN issued an order reaffirming its order from September 2021.

Regulatory Rate Review

In June 2020, Nevada Power filed an electric regulatory rate review with the PUCN. The filing supported an annual revenue reduction of $96 million but requested an annual revenue reduction of $120 million. In September 2020, Nevada Power filed an all-party settlement for the electric regulatory rate review. The settlement resolved all but one issue and provided for an annual revenue reduction of $93 million and required Nevada Power to issue a $120 million one-time bill credit, composed primarily of existing regulatory liabilities, to customers beginning in October 2020. The continuation of the earning sharing mechanism was the one issue that was not addressed in the settlement. In October 2020, the PUCN held a hearing on the continuation of the earning sharing mechanism and issued an interim order accepting the settlement and requiring the one-time bill credit be issued to customers. The $120 million one-time bill credit was issued to customers in the fourth quarter of 2020. In December 2020, the PUCN issued a final order directing Nevada Power to continue the earning sharing mechanism subject to any modifications made to the earning sharing mechanism pursuant to an alternative rate-making ruling and to use the weather normalization methodology adopted for Sierra Pacific in its 2019 regulatory rate review. The new rates were effective on January 1, 2021.

Energy Efficiency Program Rates ("EEPR") and Energy Efficiency Implementation Rates ("EEIR")

EEPR was established to allow Nevada Power 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 Nevada Power and approved by the PUCN in integrated resource plan proceedings. When Nevada Power's regulatory earned rate of return for a calendar year exceeds the regulatory rate of return used to set base tariff general rates, it is obligated to refund energy efficiency implementation revenue previously collected for that year. In March 2021, Nevada Power filed an application to reset the EEIR and EEPR and to refund the EEIR revenue received in 2020, including carrying charges. In August 2021, the PUCN issued an order accepting a stipulation requiring Nevada Power to refund the 2020 revenue and reset the rates as filed effective October 1, 2021. The EEIR liability for Nevada Power is $8 million, which is included in current regulatory liabilities on the Consolidated Balance Sheets as of December 31, 2021 and 2020.

(7) Short-term Debt and Credit Facilities

The following table summarizes Nevada Power's availability under its credit facilities as of December 31 (in millions):

	2021	2020
Credit facilities	$ 400	$ 400
Short-term debt	(180)	—
Net credit facilities	$ 220	$ 400

Nevada Power has a $400 million secured credit facility expiring in June 2024 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 Eurodollar rate 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, 2021 and 2020, Nevada Power had borrowings of $180 million and $— million, respectively, outstanding under the credit facility. As of December 31, 2021, the weighted average interest rate on borrowings outstanding was 0.86%. 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, 2021, Nevada Power had $15 million of a fully available letter of credit issued under committed arrangements in support of certain transactions required by a third party and has provisions that automatically extend the annual expiration date for an additional year unless the issuing bank elects not to renew the letter of credit prior to the expiration date.

(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	2021	2020
General and refunding mortgage securities:			
3.700% Series CC, due 2029	$ 500	$ 497	$ 496
2.400% Series DD, due 2030	425	422	422
6.650% Series N, due 2036	367	359	359
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	239	237
3.125% Series EE, due 2050	300	297	297
Tax-exempt refunding revenue bond obligations:			
Fixed-rate series:			
1.875% Pollution Control Bonds Series 2017A, due 2032(1)	40	39	39
1.650% Pollution Control Bonds Series 2017, due 2036(1)	40	39	39
1.650% Pollution Control Bonds Series 2017B, due 2039(1)	13	13	13
Total long-term debt	$ 2,534	$ 2,499	$ 2,496
Reflected as:			
Total long-term debt		$ 2,499	$ 2,496

(1) Subject to mandatory purchase by Nevada Power in March 2023 at which date the interest rate may be adjusted.

Annual Payment on Long-Term Debt

The annual repayments of long-term debt for the years beginning January 1, 2022 and thereafter, are as follows (in millions):

2027 and thereafter	$ 2,534
Unamortized premium, discount and debt issuance cost	(35)
Total	$ 2,499

In January 2022, Nevada Power entered into a $300 million secured delayed draw term loan facility maturing in January 2024. Amounts borrowed under the facility bear interest at variable rates based on the Secured Overnight Financing Rate or a base rate, at Nevada Power's option, plus a pricing margin. In January 2022, Nevada Power borrowed $200 million under the facility at an initial interest rate of 0.55%. Nevada Power may draw all or none of the remaining unused commitment through June 2022. Nevada Power used the proceeds to repay amounts outstanding under its existing secured credit facility and for general corporate purposes.

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, 2021, approximately $9.4 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):

	2021	2020	2019
Current – Federal	$ 37	$ 57	$ 105
Deferred – Federal	—	(10)	(31)
Investment tax credits	—	—	(1)
Total income tax expense	$ 37	$ 47	$ 73

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:

	2021	2020	2019
Federal statutory income tax rate	21 %	21 %	21 %
Effects of ratemaking	(11)	(8)	—
Other	1	1	1
Effective income tax rate	11 %	14 %	22 %

The net deferred income tax liability consists of the following as of December 31 (in millions):

	2021	2020
Deferred income tax assets:		
Regulatory liabilities	$ 195	$ 206
Operating and finance leases	73	79
Customer advances	25	19
Unamortized contract value	25	8
Other	8	15
Total deferred income tax assets	326	327
Deferred income tax liabilities:		
Property related items	(800)	(800)
Regulatory assets	(204)	(176)
Operating and finance leases	(70)	(76)
Other	(34)	(13)
Total deferred income tax liabilities	(1,108)	(1,065)
Net deferred income tax liability	$ (782)	$ (738)

The United States Internal Revenue Service has closed its examination of NV Energy's consolidated income tax returns through December 31, 2008, and effectively settled its examination of Nevada Power's income tax return for the short year ended December 31, 2013, and the statute of limitations has expired for NV Energy's consolidated income tax returns through the short year ended December 19, 2013. The closure or effective settlement of examinations, or the expiration of the statute of limitations may not preclude the Internal Revenue Service from adjusting the federal net operating loss carryforward utilized in a year for which the examination 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, 2021, 2020 and 2019. Nevada Power contributed $1 million to the Non-Qualified Pension Plans for the years ended December 31, 2021, 2020 and 2019. Nevada Power did not make any contributions to the Other Postretirement Plans for the years ended December 31, 2021, 2020 and 2019. 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):

	2021	2020
Qualified Pension Plan -		
Other non-current assets	$ 42	$ 8
Non-Qualified Pension Plans:		
Other current liabilities	(1)	(1)
Other long-term liabilities	(8)	(9)
Other Postretirement Plans -		
Other non-current assets	8	4

(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 $348 million and $340 million as of December 31, 2021 and 2020, respectively.

The following table presents Nevada Power's ARO liabilities by asset type as of December 31 (in millions):

	2021	2020
Waste water remediation	$ 37	$ 36
Evaporative ponds and dry ash landfills	13	13
Solar	3	3
Other	15	20
Total asset retirement obligations	$ 68	$ 72

The following table reconciles the beginning and ending balances of Nevada Power's ARO liabilities for the years ended December 31 (in millions):

	2021	2020
Beginning balance	$ 72	$ 74
Change in estimated costs	—	9
Retirements	(6)	(14)
Accretion	2	3
Ending balance	$ 68	$ 72
Reflected as:		
Other current liabilities	$ 19	$ 25
Other long-term liabilities	49	47
	$ 68	$ 72

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, natural gas and coal 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	Other Current Liabilities	Other Long-term Liabilities	Total
As of December 31, 2021:				
Not designated as hedging contracts [1]:				
Commodity assets	$ 4	$ —	$ —	$ 4
Commodity liabilities	—	(55)	(62)	(117)
Total derivative - net basis	$ 4	$ (55)	$ (62)	$ (113)
As of December 31, 2020:				
Not designated as hedging contracts[1]:				
Commodity assets	$ 26	$ —	$ —	$ 26
Commodity liabilities	—	(3)	(8)	(11)
Total derivative - net basis	$ 26	$ (3)	$ (8)	$ 15

(1) Nevada Power's commodity derivatives not designated as hedging contracts are included in regulated rates. As of December 31, 2021 a regulatory asset of $113 million was recorded related to the net derivative liability of $113 million. As of December 31, 2020 a regulatory liability of $15 million was recorded related to the net derivative asset of $15 million.

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	2021	2020
Electricity purchases	Megawatt hours	1	1
Natural gas purchases	Decatherms	119	124

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, 2021, 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 $6 million and $3 million as of December 31, 2021 and 2020, 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, 2021:				
Assets:				
Commodity derivatives	$ —	$ —	$ 4	$ 4
Money market mutual funds	34	—	—	34
Investment funds	3	—	—	3
	$ 37	$ —	$ 4	$ 41
Liabilities - commodity derivatives	$ —	$ —	$ (117)	$ (117)
As of December 31, 2020:				
Assets:				
Commodity derivatives	$ —	$ —	$ 26	$ 26
Money market mutual funds	21	—	—	21
Investment funds	2	—	—	2
	$ 23	$ —	$ 26	$ 49
Liabilities - commodity derivatives	$ —	$ —	$ (11)	$ (11)

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, 2021, 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.

Nevada Power's investments in money market mutual funds and equity securities 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.

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):

	2021	2020	2019
Beginning balance	$ 15	$ (8)	$ 3
Changes in fair value recognized in regulatory assets or liabilities	(90)	(17)	(21)
Settlements	(38)	40	10
Ending balance	$ (113)	$ 15	$ (8)

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):

	2021		2020	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 2,499	$ 3,067	$ 2,496	$ 3,245

(14) Commitments and Contingencies

Environmental Laws and Regulations

Nevada Power is subject to federal, state and local laws and regulations regarding air and water quality, renewable portfolio standards, emissions performance standards, climate change, coal combustion byproduct disposal, hazardous and solid waste disposal, protected species and other environmental matters that have the potential to impact Nevada Power's current and future operations. Nevada Power believes it is in material compliance with all applicable laws and regulations.

Senate Bill 123

In June 2013, the Nevada State Legislature passed Senate Bill 123 ("SB 123"), which included the retirement of coal plants and replacing the capacity with renewable facilities and other generating facilities. In May 2014, Nevada Power filed its Emissions Reduction and Capacity Replacement Plan ("ERCR Plan") in compliance with SB 123. In July 2015, Nevada Power filed an amendment to its ERCR Plan with the PUCN which was approved in September 2015. In June 2015, the Nevada State Legislature passed Assembly Bill No. 498, which modified the capacity replacement components of SB 123.

In compliance with SB 123, Nevada Power retired 255 MWs of coal-fueled generation in 2019 in addition to the 557 MWs of coal-fueled generation retired in 2017. Consistent with the ERCR Plan, between 2014 and 2016, Nevada Power acquired 536 MWs of natural gas generating resources, executed long-term power purchase agreements for 200 MWs of nameplate renewable energy capacity and constructed a 15-MW solar photovoltaic facility. Nevada Power has the option to acquire 35 MWs of nameplate renewable energy capacity in the future under the ERCR Plan, subject to PUCN approval.

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.

Commitments

Nevada Power has the following firm commitments that are not reflected on the Consolidated Balance Sheet. Minimum payments as of December 31, 2021 are as follows (in millions):

	2022	2023	2024	2025	2026	2027 and Thereafter	Total
Contract type:							
Fuel, capacity and transmission contract commitments	$ 713	$ 458	$ 346	$ 348	$ 352	$ 3,250	$ 5,467
Fuel and capacity contract commitments (not commercially operable)	20	60	181	212	211	4,302	4,986
Construction commitments	141	209	—	—	—	—	350
Easements	4	5	2	2	2	52	67
Maintenance, service and other contracts	51	34	23	18	14	33	173
Total commitments	$ 929	$ 766	$ 552	$ 580	$ 579	$ 7,637	$11,043

Fuel and Capacity Contract Commitments

Purchased Power

Nevada Power has several contracts for long-term purchase of electric energy which have been approved by the PUCN. The expiration of these contracts range from 2026 to 2067. Purchased power includes estimated payments for contracts which meet the definition of a lease and payments are based on the amount of energy expected to be generated. See Note 5 for further discussion of Nevada Power's lease commitments.

Natural Gas

Nevada Power's gas transportation contracts expire from 2022 to 2039 and the gas supply contracts expires from 2022 to 2023.

Fuel and Capacity Contract Commitments - Not 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.

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 and certain other generating plant projects.

Easements

Nevada Power has non-cancelable easements for land. Operations and maintenance expense on non-cancelable easements totaled $4 million, $4 million and $7 million for the years ended December 31, 2021, 2020 and 2019, respectively.

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 2022 to 2031.

(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):

	2021	2020	2019
Customer Revenue:			
Retail:			
Residential	$ 1,207	$ 1,145	$ 1,141
Commercial	414	384	441
Industrial	386	345	433
Other	14	12	20
Total fully bundled	2,021	1,886	2,035
Distribution only service	22	24	31
Total retail	2,043	1,910	2,066
Wholesale, transmission and other	74	62	57
Total Customer Revenue	2,117	1,972	2,123
Other revenue	22	26	25
Total revenue	$ 2,139	$ 1,998	$ 2,148

(16) Supplemental Cash Flow Disclosures

Cash and Cash Equivalents and Restricted Cash and Cash Equivalents

Cash equivalents consist of funds invested in money market mutual funds, United States 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 as of December 31, 2021 and December 31, 2020, 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, 2021 and December 31, 2020, as presented in 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, 2021	December 31, 2020
Cash and cash equivalents	$ 33	$ 25
Restricted cash and cash equivalents included in other current assets	12	11
Total cash and cash equivalents and restricted cash and cash equivalents	$ 45	$ 36

The summary of supplemental cash flow disclosures as of and for the years ended December 31 is as follows (in millions):

	2021	2020	2019
Supplemental disclosure of cash flow information:			
Interest paid, net of amounts capitalized	$ 115	$ 115	$ 126
Income taxes paid	$ 63	$ 50	$ 113
Supplemental disclosure of non-cash investing and financing transactions:			
Accruals related to property, plant and equipment additions	$ 53	$ 32	$ 49

(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 totaled $3 million, $2 million and $2 million for the years ended December 31, 2021, 2020 and 2019, respectively.

Kern River Gas Transmission Company, an indirect subsidiary of BHE, provided natural gas transportation and other services to Nevada Power of $52 million for the years ended December 31, 2021, 2020 and 2019. As of December 31, 2021 and 2020, Nevada Power's Consolidated Balance Sheets included amounts due to Kern River Gas Transmission Company of $4 million.

Nevada Power provided electricity and other services to PacifiCorp, an indirect subsidiary of BHE, of $3 million, $3 million and $2 million for the years ended December 31, 2021, 2020 and 2019, respectively. There were no receivables associated with these services as of December 31, 2021 and 2020. PacifiCorp provided electricity and the sale of renewable energy credits to Nevada Power of $— million, $1 million and $— million for the years ended December 31, 2021, 2020, and 2019, respectively. There were no payables associated with these transactions as of December 31, 2021 and 2020.

Nevada Power provided electricity to Sierra Pacific of $179 million, $106 million and $84 million for the years ended December 31, 2021, 2020 and 2019, respectively. Receivables associated with these transactions were $13 million as of December 31, 2021 and 2020. Nevada Power purchased electricity from Sierra Pacific of $43 million, $34 million and $25 million for the years ended December 31, 2021, 2020 and 2019, respectively. Payables associated with these transactions were $— million and $1 million as of December 31, 2021 and 2020, 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 $1 million, $— million and $— million for each of the years ending December 31, 2021, 2020 and 2019, respectively. NV Energy provided services to Nevada Power of $9 million for the years ending December 31, 2021, 2020 and 2019. Nevada Power provided services to Sierra Pacific of $25 million, $26 million and $26 million for the years ended December 31, 2021, 2020 and 2019, respectively. Sierra Pacific provided services to Nevada Power of $15 million, $15 million and $14 million for the years ended December 31, 2021, 2020 and 2019, respectively. As of December 31, 2021 and 2020, Nevada Power's Consolidated Balance Sheets included amounts due to NV Energy of $33 million and $28 million, respectively. There were no receivables due from NV Energy as of December 31, 2021 and 2020. As of December 31, 2021 and 2020, Nevada Power's Consolidated Balance Sheets included receivables due from Sierra Pacific of $2 million. There were no payables due to Sierra Pacific as of December 31, 2021 and 2020.

Nevada Power is party to a tax-sharing agreement with NV Energy and NV Energy is part of the Berkshire Hathaway consolidated United States federal income tax return. As of December 31, 2021 and 2020 federal income taxes receivable from NV Energy were $27 million and $— million, respectively. Nevada Power made cash payments of $63 million, $50 million and $113 million for federal income taxes for the years ended December 31, 2021, 2020 and 2019, respectively.

Certain disbursements for accounts payable and payroll are made by NV Energy on behalf of Nevada Power and reimbursed automatically when settled by the bank. These amounts are recorded as accounts payable at the time of disbursement.

Sierra Pacific Power Company and its subsidiaries
Consolidated Financial Section

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

The following is management's discussion and analysis of certain significant factors that have affected the 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, 2021 was $124 million, an increase of $13 million, or 12%, compared to 2020, primarily due to $5 million of higher interest and dividend income, mainly from carrying charges on regulatory balances, $4 million of higher electric utility margin, mainly from price impacts from changes in sales mix and an increase in the average number of customer, primarily from the residential customer class, partially offset by lower revenue recognized due to a favorable regulatory decision and an adjustment to regulatory-related revenue deferrals, $4 million of higher other, net, mainly due to lower pension expense and higher cash surrender value of corporate-owned life insurance policies, $3 million of higher allowance for equity funds, mainly due to higher construction work-in-progress, $2 million of higher natural gas utility margin, mainly due to higher commercial usage, and $2 million of lower interest expense, mainly due to lower carrying charges on regulatory balances, partially offset by $3 million of higher income tax expense primarily due to higher pretax income, $2 million of higher depreciation and amortization, mainly from regulatory amortizations and higher plant in-service, and $1 million of higher operations and maintenance expenses, mainly due to higher plant operations and maintenance expenses and higher legal expenses, offset by lower earnings sharing.

Net income for the year ended December 31, 2020 was $111 million, an increase of $8 million, or 8%, compared to 2019, primarily due to $13 million of lower income tax expense due to the recognition of amortization of excess deferred income taxes following regulatory approval effective January 1, 2020, $10 million of lower operations and maintenance expenses, primarily due to higher regulatory-directed credits, and $4 million of higher electric utility margin, partially offset by $16 million of higher depreciation and amortization, mainly due to higher plant in-service, and $3 million of lower natural gas utility margin.

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):

	2021	2020	Change		2020	2019	Change	
Electric utility margin:								
Operating revenue	$ 848	$ 738	$ 110	15 %	$ 738	$ 770	$ (32)	(4)%
Cost of fuel and energy	407	301	106	35	301	337	(36)	(11)
Electric utility margin	441	437	4	1 %	437	433	4	1 %
Natural gas utility margin:								
Operating revenue	117	116	1	1 %	116	119	(3)	(3)%
Natural gas purchased for resale	61	62	(1)	(2)	62	62	—	—
Natural gas utility margin	56	54	2	4 %	54	57	(3)	(5)%
Utility margin	497	491	6	1 %	491	490	1	— %
Operations and maintenance	163	162	1	1 %	162	172	(10)	(6)%
Depreciation and amortization	143	141	2	1	141	125	16	13
Property and other taxes	24	23	1	4	23	22	1	5
Operating income	$ 167	$ 165	$ 2	1 %	$ 165	$ 171	$ (6)	(4)%

Electric Utility Margin

A comparison of key operating results related to electric utility margin is as follows for the years ended December 31:

	2021	2020	Change		2020	2019	Change	
Utility margin (in millions):								
Operating revenue	$ 848	$ 738	$ 110	15 %	$ 738	$ 770	$ (32)	(4)%
Cost of fuel and energy	407	301	106	35	301	337	(36)	(11)
Utility margin	$ 441	$ 437	$ 4	1 %	$ 437	$ 433	$ 4	1 %
Sales (GWhs):								
Residential	2,769	2,672	97	4 %	2,672	2,491	181	7 %
Commercial	3,056	2,977	79	3	2,977	2,973	4	—
Industrial	3,716	3,544	172	5	3,544	3,716	(172)	(5)
Other	15	15	—	—	15	16	(1)	(6)
Total fully bundled[(1)]	9,556	9,208	348	4	9,208	9,196	12	—
Distribution only service	1,639	1,670	(31)	(2)	1,670	1,629	41	3
Total retail	11,195	10,878	317	3	10,878	10,825	53	—
Wholesale	656	548	108	20	548	662	(114)	(17)
Total GWhs sold	11,851	11,426	425	4 %	11,426	11,487	(61)	(1)%
Average number of retail customers (in thousands)	365	359	6	2 %	359	352	7	2 %
Average revenue per MWh:								
Retail - fully bundled[(1)]	$ 81.77	$ 73.89	$ 7.88	11 %	$ 73.89	$ 76.72	$ (2.83)	(4)%
Wholesale	$ 58.14	$ 52.52	$ 5.62	11 %	$ 52.52	$ 48.54	$ 3.98	8 %
Heating degree days	4,494	4,477	17	— %	4,477	4,728	(251)	(5)%
Cooling degree days	1,366	1,176	190	16 %	1,176	1,107	69	6 %
Sources of energy (GWhs)[(2)(3)]:								
Natural gas	4,712	5,219	(507)	(10)%	5,219	4,891	328	7 %
Coal	1,220	855	365	43	855	1,205	(350)	(29)
Renewables[(4)]	31	37	(6)	(16)	37	37	—	—
Total energy generated	5,963	6,111	(148)	(2)	6,111	6,133	(22)	—
Energy purchased	4,960	4,753	207	4	4,753	4,466	287	6
Total	10,923	10,864	59	1 %	10,864	10,599	265	3 %
Average cost of energy per MWh[(5)]:								
Energy generated	$ 28.84	$ 20.12	$ 8.72	43 %	$ 20.12	$ 26.29	$ (6.17)	(23)%
Energy purchased	$ 47.39	$ 37.46	$ 9.93	27 %	$ 37.46	$ 39.39	$ (1.93)	(5)%

(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 2, 10 and - GWhs of coal and 6, 31 and - GWhs of natural gas generated energy that is purchased at cost by related parties for the years ended December 31, 2021, 2020 and 2019, respectively.

(3) GWh amounts are net of energy used by the related generating facilities.

(4) Includes the Fort Churchill Solar Array which was under lease by Sierra Pacific until it was acquired in December 2021.

(5) 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:

	2021	2020	Change		2020	2019	Change	
Utility margin (in millions):								
Operating revenue	$ 117	$ 116	$ 1	1 %	$ 116	$ 119	$ (3)	(3)%
Natural gas purchased for resale	61	62	(1)	(2)	62	62	—	—
Utility margin	$ 56	$ 54	$ 2	4 %	$ 54	$ 57	$ (3)	(5)%
Sold (000's Dths):								
Residential	10,662	10,452	210	2 %	10,452	11,311	(859)	(8)%
Commercial	5,524	5,148	376	7	5,148	5,783	(635)	(11)
Industrial	1,981	1,826	155	8	1,826	1,971	(145)	(7)
Total retail	18,167	17,426	741	4 %	17,426	19,065	(1,639)	(9)%
Average number of retail customers (in thousands)	177	174	3	2 %	174	170	4	2 %
Average revenue per retail Dth sold	$ 6.44	$ 6.66	$ (0.22)	(3)%	$ 6.66	$ 6.24	$ 0.42	7 %
Heating degree days	4,494	4,477	17	— %	4,477	4,728	(251)	(5)%
Average cost of natural gas per retail Dth sold	$ 3.36	$ 3.56	$ (0.20)	(6)%	$ 3.56	$ 3.25	$ 0.31	9 %

Year Ended December 31, 2021 Compared to Year Ended December 31, 2020

Electric utility margin increased $4 million, or 1%, for 2021 compared to 2020 primarily due to:

- $10 million of higher electric retail utility margin primarily due to higher retail customer volumes. Retail customer volumes, including distribution only service customers, increased 2.9% primarily due to an increase in the average number of customers, favorable changes in customer usage patterns and the favorable impact of weather, and
- $3 million of higher transmission and wholesale revenue.

The increase in electric utility margin was offset by:

- $3 million in lower revenue recognized due to a favorable regulatory decision in 2020;
- $3 million due to an adjustment to regulatory-related revenue deferrals; and
- $2 million due to lower energy efficiency program costs (offset in operations and maintenance expense).

Natural gas utility margin increased $2 million, or 4%, for 2021 compared to 2020 primarily due to favorable changes in customer usage patterns.

Operations and maintenance increased $1 million, or 1%, for 2021 compared to 2020 primarily due to higher plant operations and maintenance expenses and higher legal expenses, offset by lower earnings sharing and lower energy efficiency program costs (offset in operating revenue).

Depreciation and amortization increased $2 million, or 1%, for 2021 compared to 2020 primarily due to regulatory amortizations and higher plant in-service.

Interest expense decreased $2 million, or 4%, for 2021 compared to 2020 primarily due to lower carrying charges on regulatory balances.

Allowance for equity funds increased $3 million, or 75%, for 2021 compared to 2020 primarily due to higher construction work-in-progress.

Interest and dividend income increased $5 million for 2021 compared to 2020 primarily due to higher interest income, mainly from carrying charges on regulatory balances.

Other, net increased $4 million, or 57%, for 2021 compared to 2020 primarily due to lower pension expense and higher cash surrender value of corporate-owned life insurance policies.

Income tax expense increased $3 million, or 20%, for 2021 compared to 2020 primarily due to higher pretax income. The effective tax rate was 13% in 2021 and 12% in 2020.

Year Ended December 31, 2020 Compared to Year Ended December 31, 2019

Electric utility margin increased $4 million, or 1%, for 2020 compared to 2019 primarily due to:

- $4 million in higher residential customer volumes from the favorable impact of weather;
- $3 million due to higher energy efficiency program costs (offset in operations and maintenance expense); and
- $2 million of residential customer growth.

The increase in electric utility margin was offset by:

- $4 million of lower transmission and wholesale revenue; and
- $1 million of higher revenue reductions related to customer service agreements.

Natural gas utility margin decreased $3 million, or 5%, for 2020 compared to 2019 primarily due to lower customer volumes mainly from the unfavorable impacts of weather.

Operations and maintenance decreased $10 million, or 6%, for 2020 compared to 2019 primarily due to higher regulatory-directed credits relating to the deferral of costs for the ON Line lease to be collected from customers due to the regulatory-directed reallocation of costs between Nevada Power and Sierra Pacific (offset in depreciation and amortization and other income (expense)) of $9 million and lower plant operations and maintenance expenses, offset by lower regulatory-directed credits relating to the amortization of an excess reserve balance that ended in 2019 and higher energy efficiency program costs (offset in operating revenue).

Depreciation and amortization increased $16 million, or 13%, for 2020 compared to 2019 primarily due to higher plant placed in-service and higher depreciation expense on the ON Line lease due to the regulatory-directed reallocation of costs between Nevada Power and Sierra Pacific (offset in operations and maintenance expense).

Other income (expense) is favorable $1 million, or 3%, for 2020 compared to 2019 primarily due to lower pension costs, partially offset by higher interest expense on the ON Line lease due to the regulatory-directed reallocation of costs between Nevada Power and Sierra Pacific (offset in operations and maintenance expense).

Income tax expense decreased $13 million, or 46%, for 2020 compared to 2019. The effective tax rate was 12% in 2020 and 21% in 2019 and decreased due to the recognition of amortization of excess deferred income taxes following regulatory approval effective January 1, 2020.

Liquidity and Capital Resources

As of December 31, 2021, Sierra Pacific's total net liquidity was $101 million as follows (in millions):

Cash and cash equivalents	$	10
Credit facilities[1]		250
Less -		
Short-term debt		(159)
Net credit facilities		91
Total net liquidity	$	101
Credit facilities:		
Maturity dates		2024

(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, 2021 and 2020 were $183 million and $190 million, respectively. The change was primarily due to the timing of payments for fuel and energy costs, partially offset by higher collections from customers, the timing of payments for operating costs, lower inventory purchases and increased collections of customer advances.

Net cash flows from operating activities for the years ended December 31, 2020 and 2019 were $190 million and $237 million, respectively. The change was primarily due to lower collections from customers, higher inventory purchases, the timing of payments for operating costs and higher payments for fuel and energy costs, partially offset by lower payments for income taxes.

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, 2021 and 2020 were $(300) million and $(246) 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, 2020 and 2019 were $(246) million and $(247) million, respectively. The change was primarily due to decreased capital expenditures, partially offset by expenditures related to the regulatory-directed reallocation of ON Line assets between Nevada Power and Sierra Pacific. 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, 2021 and 2020 were $107 million and $50 million, respectively. The change was primarily due to higher proceeds from short-term debt and lower dividends paid to NV Energy, Inc., partially offset by lower proceeds from the issuance of long-term debt.

Net cash flows from financing activities for the years ended December 31, 2020 and 2019 were $50 million and $(34) million, respectively. The change was primarily due to lower payments to repurchase long-term debt, higher proceeds from short-term debt and lower dividends paid to NV Energy, Inc., partially offset by lower proceeds from the re-offering of previously repurchased long-term debt.

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, 2021, 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 $250 million secured credit facility) does not exceed $1.6 billion 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, 2021. 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.

In January 2022, the PUCN approved Sierra Pacific's request to increase its financing authority for debt securities to not exceed $1.9 billion as measured at the end of each calendar quarter. Additionally, the PUCN authorized Sierra Pacific to issue common and preferred stock so long as the total amounts outstanding do not exceed $2.2 billion and $500 million, respectively, at the end of each calendar quarter.

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, 2021, $4.5 billion of Sierra Pacific's assets were pledged. Sierra Pacific had the capacity to issue $1.7 billion of additional general and refunding mortgage securities as of December 31, 2021 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.

Common Shareholder's Equity

In January 2022, Sierra Pacific received a capital contribution of $130 million from NV Energy, Inc.

<u>Future Uses of Cash</u>

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		
	2019	2020	2021	2022	2023	2024
Electric distribution	$ 156	$ 128	$ 96	$ 122	$ 129	$ 112
Electric transmission	17	60	77	164	242	326
Solar generation	—	—	17	1	134	197
Other	72	58	110	160	100	74
Total	$ 245	$ 246	$ 300	$ 447	$ 605	$ 709

Sierra Pacific received 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 in its forecast capital expenditures for 2022 through 2024. These estimates are likely to change as a result of the RFP process. 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. In this project, the company has received approval from the PUCN to build a 350-mile, 525-kV transmission line, known as Greenlink West, connecting the Ft. Churchill substation to the Northwest substation to the Harry Allen substation; a 235-mile, 525-kV transmission line, known as Greenlink North, connecting the new Ft. Churchill substation to the Robinson Summit substation; a 46-mile, 345-kV transmission line from the new Ft. Churchill substation to the Mira Loma substations; and a 38-mile, 345-kV transmission line from the new Ft. Churchill substation to the Robinson Summit substations. Operating expenditures consist of routine expenditures for transmission and other infrastructure needed to serve existing and expected demand.
- Solar generation includes growth projects consisting of two solar photovoltaic facilities. The first project is a 250-MW solar photovoltaic facility with an additional 200 MWs of co-located battery storage that will be developed in Humboldt County, Nevada. Commercial operation is expected by the end of 2023. The second project is a 350-MW solar photovoltaic facility with an additional 280 MWs of co-located battery storage that will be developed in Humboldt County, Nevada. Commercial operation is expected by the end of 2024. Both facilities will be jointly owned and operated by Nevada Power and Sierra Pacific.
- Other includes both growth projects and operating expenditures consisting of turbine upgrades at the Tracy generating facility, routine expenditures for generation, other operating projects and other infrastructure needed to serve existing and expected demand.

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 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 $411 million on long-term debt, including $41 million due in 2022.

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 climate change, RPS, air and water quality, emissions performance standards, coal combustion byproduct disposal, hazardous and solid waste disposal, protected species 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 "Liquidity and Capital Resources" for discussion of Sierra Pacific's forecasted environmental-related capital expenditures.

Refer to "Environmental Laws and Regulations" in Item 1 of this Form 10-K for additional information 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, 2021, 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, 2021, Sierra Pacific would have been required to post $18 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 structure administered by the PUCN and the FERC. Under this rate 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.

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 the 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 $440 million and total regulatory liabilities were $463 million as of December 31, 2021. 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 the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value and any resulting impairment loss is reflected on the Consolidated Statements of Operations. As substantially all property, plant and equipment was used in regulated businesses as of December 31, 2021, 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 the asset that are used in the impairment analysis requires judgment regarding what Sierra Pacific would expect to recover from the future use of the asset. Changes in judgment that could significantly alter the calculation of the fair value or the recoverable amount of the asset may result from significant changes in the regulatory environment, the business climate, management's plans, legal factors, market price of the asset, the use of the asset or 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, if any, 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 benefits and expense related to the federal tax rate change from 35% to 21% as a result of 2017 Tax Reform, certain property-related basis differences and other various differences on to its customers. As of December 31, 2021, these amounts were recognized as a net regulatory liability of $234 million and will be included in regulated rates when the temporary differences reverse.

Revenue Recognition - Unbilled Revenue

Revenue is recognized as electricity or natural gas is delivered or services are provided. The determination of customer billings is based on a systematic reading of meters. At the end of each month, energy provided to customers since their last billing is estimated, and the corresponding unbilled revenue is recorded. Unbilled revenue was $78 million as of December 31, 2021. 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. Estimates are reversed in the following month when actual revenue is recorded.

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, 2021:			
Total commodity derivative contracts	$ (33)	$ (26)	$ (40)
As of December 31, 2020:			
Total commodity derivative contracts	$ 7	$ 8	$ 6

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, 2021 and 2020, a net regulatory asset of $33 million and net regulatory liability of $7 million, respectively, was recorded related to the net derivative liability of $33 million and net derivative asset of $7 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, 2021 and 2020, Sierra Pacific had short-term variable-rate obligations totaling $159 million and $45 million, respectively, 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, 2021 and 2020.

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, 2021, 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	377
Consolidated Balance Sheets	379
Consolidated Statements of Operations	380
Consolidated Statements of Changes in Shareholder's Equity	381
Consolidated Statements of Cash Flows	382
Notes to Consolidated Financial Statements	383

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, 2021 and 2020, 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, 2021, 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, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021, 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 — Impact of Rate Regulation on the Financial Statements — Refer to Notes 2 and 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 it meets 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 impacts multiple financial statement line items and disclosures, such as property, plant, and equipment, net; regulatory assets and liabilities; deferred income taxes; operating revenue; operations and maintenance expense; depreciation and amortization expense, and income tax expense.

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 impact 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 impact of rate regulation as a critical audit matter due to the significant judgments made by management to support its assertions about impacted account balances and disclosures and the high degree of subjectivity involved in assessing the impact of future 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 future 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 impacts of rate regulation, including the balances recorded and regulatory developments.
- We read relevant regulatory orders issued by the Commissions, regulatory statutes, interpretations, procedural memorandums, filings made by interveners, and other publicly available information 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 evaluated the external information and compared to management's recorded regulatory asset and liability balances for completeness.
- For regulatory matters in process, we inspected Sierra Pacific's filings with the Commissions and the filings with the Commissions by intervenors that may impact Sierra Pacific's future rates, for any evidence that might contradict management's assertions.
- 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 25, 2022

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,	
	2021	**2020**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 10	$ 19
Trade receivables, net	128	97
Inventories	65	77
Regulatory assets	177	67
Other current assets	35	45
Total current assets	415	305
Property, plant and equipment, net	3,340	3,164
Regulatory assets	263	267
Other assets	205	183
Total assets	$ 4,223	$ 3,919
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities:		
Accounts payable	$ 147	$ 108
Accrued interest	14	14
Accrued property, income and other taxes	16	14
Short-term debt	159	45
Regulatory liabilities	19	34
Customer deposits	15	15
Other current liabilities	44	25
Total current liabilities	414	255
Long-term debt	1,164	1,164
Finance lease obligations	106	121
Regulatory liabilities	444	463
Deferred income taxes	402	374
Other long-term liabilities	158	131
Total liabilities	2,688	2,508
Commitments and contingencies (Note 14)		
Shareholder's equity:		
Common stock - $3.75 stated value, 20,000,000 shares authorized and 1,000 issued and outstanding	—	—
Additional paid-in capital	1,111	1,111
Retained earnings	425	301
Accumulated other comprehensive loss, net	(1)	(1)
Total shareholder's equity	1,535	1,411
Total liabilities and shareholder's equity	$ 4,223	$ 3,919

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,		
	2021	**2020**	**2019**
Operating revenue:			
Regulated electric	$ 848	$ 738	$ 770
Regulated natural gas	117	116	119
Total operating revenue	965	854	889
Operating expenses:			
Cost of fuel and energy	407	301	337
Cost of natural gas purchased for resale	61	62	62
Operations and maintenance	163	162	172
Depreciation and amortization	143	141	125
Property and other taxes	24	23	22
Total operating expenses	798	689	718
Operating income	167	165	171
Other income (expense):			
Interest expense	(54)	(56)	(48)
Allowance for borrowed funds	2	2	1
Allowance for equity funds	7	4	3
Interest and dividend income	9	4	3
Other, net	11	7	1
Total other income (expense)	(25)	(39)	(40)
Income before income tax expense	142	126	131
Income tax expense	18	15	28
Net income	$ 124	$ 111	$ 103

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, 2018	1,000	$ —	$ 1,111	$ 153	$ —	$ 1,264
Net income	—	—	—	103	—	103
Dividends declared	—	—	—	(46)	—	(46)
Other equity transactions	—	—	—	—	(1)	(1)
Balance, December 31, 2019	1,000	—	1,111	210	(1)	1,320
Net income	—	—	—	111	—	111
Dividends declared	—	—	—	(20)	—	(20)
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

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, 2021	2020	2019
Cash flows from operating activities:			
Net income	$ 124	$ 111	$ 103
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	143	141	125
Allowance for equity funds	(7)	(4)	(3)
Changes in regulatory assets and liabilities	(39)	(33)	25
Deferred income taxes and amortization of investment tax credits	13	12	9
Deferred energy	(116)	(17)	15
Amortization of deferred energy	29	(14)	(2)
Other, net	(1)	(2)	—
Changes in other operating assets and liabilities:			
Trade receivables and other assets	(27)	(81)	(6)
Inventories	12	(19)	(5)
Accrued property, income and other taxes	9	9	(16)
Accounts payable and other liabilities	43	87	(8)
Net cash flows from operating activities	183	190	237
Cash flows from investing activities:			
Capital expenditures	(300)	(246)	(248)
Other, net	—	—	1
Net cash flows from investing activities	(300)	(246)	(247)
Cash flows from financing activities:			
Proceeds from long-term debt	—	30	125
Repayments of long-term debt	—	—	(109)
Net proceeds from short-term debt	114	45	—
Dividends paid	—	(20)	(46)
Other, net	(7)	(5)	(4)
Net cash flows from financing activities	107	50	(34)
Net change in cash and cash equivalents and restricted cash and cash equivalents	(10)	(6)	(44)
Cash and cash equivalents and restricted cash and cash equivalents at beginning of period	26	32	76
Cash and cash equivalents and restricted cash and cash equivalents at end of period	$ 16	$ 26	$ 32

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 United States 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 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, 2021, 2020 and 2019.

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 in 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 Equivalents and Restricted Cash and Investments

Cash equivalents consist of funds invested in money market mutual funds, United States 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 amounts are included in other current assets and other assets on the Consolidated Balance Sheets.

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):

	2021	2020	2019
Beginning balance	$ 2	$ 2	$ 2
Charged to operating costs and expenses, net	2	2	1
Write-offs, net	(3)	(2)	(1)
Ending balance	$ 1	$ 2	$ 2

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 $62 million and $67 million as of December 31, 2021 and 2020, respectively, and fuel, which includes coal stock, stored natural gas and fuel oil, totaling $3 million and $10 million as of December 31, 2021 and 2020, 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 2021 and 2020 was 6.75% for electric, 5.75% for natural gas and 6.65% 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 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 the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value and any resulting impairment loss is reflected on the Consolidated Statements of Operations. As substantially all property, plant and equipment was used in regulated businesses as of December 31, 2021, 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.

Income Taxes

Berkshire Hathaway includes Sierra Pacific in its consolidated United States federal income tax return. Consistent with established regulatory practice, Sierra Pacific's provision for income taxes has been computed on a separate return 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 that are associated with components of other comprehensive income ("OCI") are charged or credited directly to OCI. Changes in deferred income tax assets and liabilities that are 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 generally 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.

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, 2021 and 2020, trade receivables, net on the Consolidated Balance Sheets relate substantially to Customer Revenue, including unbilled revenue of $78 million and $59 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 on a straight-line basis.

(3) Property, Plant and Equipment, Net

Property, plant and equipment, net consists of the following as of December 31 (in millions):

	Depreciable Life	2021	2020
Utility plant:			
Electric generation	25 - 60 years	$ 1,163	$ 1,130
Electric transmission	50 - 100 years	940	908
Electric distribution	20 - 100 years	1,846	1,754
Electric general and intangible plant	5 - 70 years	204	189
Natural gas distribution	35 - 70 years	438	429
Natural gas general and intangible plant	5 - 70 years	14	15
Common general	5 - 70 years	370	355
Utility plant		4,975	4,780
Accumulated depreciation and amortization		(1,854)	(1,755)
Utility plant, net		3,121	3,025
Other non-regulated, net of accumulated depreciation and amortization	70 years	—	2
Plant, net		3,121	3,027
Construction work-in-progress		219	137
Property, plant and equipment, net		$ 3,340	$ 3,164

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, 2021, 2020 and 2019 was 3.1%, 3.2% 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 2016.

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, 2021 (dollars in millions):

	Sierra Pacific's Share	Utility Plant	Accumulated Depreciation	Construction Work-in-Progress
Valmy Generating Station	50 %	$ 394	$ 309	$ 1
ON Line Transmission Line	6	40	8	—
Valmy Transmission	50	4	2	—
Total		$ 438	$ 319	$ 1

(5) Leases

The following table summarizes Sierra Pacific's leases recorded on the Consolidated Balance Sheet as of December 31 (in millions):

	2021	2020
Right-of-use assets:		
Operating leases	$ 15	$ 16
Finance leases	111	126
Total right-of-use assets	$ 126	$ 142
Lease liabilities:		
Operating leases	$ 15	$ 16
Finance leases	115	130
Total lease liabilities	$ 130	$ 146

The following table summarizes Sierra Pacific's lease costs for the years ended December 31 (in millions):

	2021	2020	2019
Variable	$ 86	$ 78	$ 69
Operating	1	2	1
Finance:			
Amortization	5	4	2
Interest	9	9	2
Total lease costs	$ 101	$ 93	$ 74
Weighted-average remaining lease term (years):			
Operating leases	27.4	27.2	26.3
Finance leases	28.4	27.8	20.9
Weighted-average discount rate:			
Operating leases	5.0 %	5.0 %	5.0 %
Finance leases	8.2 %	8.1 %	7.1 %

The following table summarizes Sierra Pacific's supplemental cash flow information relating to leases for the years ended December 31 (in millions):

	2021	2020	2019
Cash paid for amounts included in the measurement of lease liabilities:			
Operating cash flows from operating leases	$ (1)	$ (2)	$ (3)
Operating cash flows from finance leases	(9)	(6)	(3)
Financing cash flows from finance leases	(7)	(5)	(3)
Right-of-use assets obtained in exchange for lease liabilities:			
Finance leases	$ 1	$ 89	$ 5

Sierra Pacific has the following remaining lease commitments as of December 31, 2021 (in millions):

	Operating	Finance	Total
2022	$ 1	$ 16	$ 17
2023	1	16	17
2024	1	15	16
2025	1	15	16
2026	1	15	16
Thereafter	24	149	173
Total undiscounted lease payments	29	226	255
Less - amounts representing interest	(14)	(111)	(125)
Lease liabilities	$ 15	$ 115	$ 130

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, previously split 95% for Nevada Power and 5% for Sierra Pacific. In December 2019, the PUCN ordered the Nevada Utilities to complete the necessary procedures to change the ownership split to 75% for Nevada Power and 25% for Sierra Pacific, effective January 1, 2020. In August 2020, the FERC approved the amended agreement between the Nevada Utilities and Great Basin Transmission, LLC that reallocated the PUCN-approved ownership percentage change from Nevada Power to 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 $110 million and $122 million were included on the Consolidated Balance Sheets as of December 31, 2021 and 2020, 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	2021	2020
Deferred energy costs	1 year	$ 107	$ 22
Merger costs from 1999 merger	25 years	66	68
Natural disaster protection plan	1 year	62	45
Employee benefit plans[(1)]	8 years	46	81
Unrealized loss on regulated derivative contracts	1 year	35	2
Deferred operating costs	8 years	31	27
Abandoned projects	5 years	19	22
Other	Various	74	67
Total regulatory assets		$ 440	$ 334
Reflected as:			
Current assets		$ 177	$ 67
Noncurrent assets		263	267
Total regulatory assets		$ 440	$ 334

(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 $158 million and $149 million as of December 31, 2021 and 2020, 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, losses on reacquired debt, AROs and legacy meters.

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	2021	2020
Deferred income taxes[1]	Various	$ 234	$ 249
Cost of removal[2]	36 years	201	197
Other	Various	28	51
Total regulatory liabilities		$ 463	$ 497
Reflected as:			
Current liabilities		$ 19	$ 34
Noncurrent liabilities		444	463
Total regulatory liabilities		$ 463	$ 497

(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.

Natural Disaster Protection Plan ("NDPP")

In March 2021, Sierra Pacific filed an application seeking recovery of the 2020 expenditures, approval for an update to the initial NDPP that was ordered by the PUCN and filed their first amendment to the 2020 NDPP. A hearing related to the application for approval of the first amendment to the 2020 NDPP was held in June 2021. Sierra Pacific filed a partial-party stipulation resolving all issues. One of the intervening parties filed an opposition to the partial-party stipulation and other intervenors filed legal briefs. The partial-party stipulation was approved by the PUCN in June 2021 with the lone dissenting party retaining the right to argue a single issue in future proceedings with the primary issue being a single statewide rate as a cost recovery mechanism. In July 2021, a hearing was held on the cost recovery of 2020 expenditures. In September 2021, the PUCN issued an order, approving the recovery of the 2020 expenditures with adjustments for vegetation management, inspections and corrections and rate structure. Certain vegetation management expenditures were to be removed from the NDPP rate and deemed to be recovered through the general three-year regulatory rate review process. A portion of the inspections and corrections were deferred to seek recovery in a future NDPP rate filing. Lastly, the order approved cost recovery based on a hybrid rate calculation comprised of a statewide rate component for operating costs and a service territory specific rate component for capital costs. In September 2021, Sierra Pacific and one of the intervening parties filed petitions for reconsideration that were granted by the PUCN. In January 2022, the PUCN issued an order reaffirming its order from September 2021.

Energy Efficiency Program Rates ("EEPR") and Energy Efficiency Implementation Rates ("EEIR")

EEPR was established to allow Sierra Pacific 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 Sierra Pacific. When Sierra Pacific's regulatory earned rate of return for a calendar year exceeds the regulatory rate of return used to set base tariff general rates, it is obligated to refund energy efficiency implementation revenue previously collected for that year. In March 2021, Sierra Pacific filed an application to reset the EEIR and EEPR and to refund the EEIR revenue received in 2020, including carrying charges. In August 2021, the PUCN issued an order accepting a stipulation requiring Sierra Pacific to refund the 2020 revenue and reset the rates as filed effective October 1, 2021.The EEIR liability for Sierra Pacific is $1 million and $2 million, which is included in current regulatory liabilities on the Consolidated Balance Sheets as of December 31, 2021 and 2020, respectively.

(7) Short-term Debt and Credit Facilities

The following table summarizes Sierra Pacific's availability under its credit facilities as of December 31 (in millions):

	2021	2020
Credit facilities	$ 250	$ 250
Short-term debt	(159)	(45)
Net credit facilities	$ 91	$ 205

Sierra Pacific has a $250 million secured credit facility expiring in June 2024 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 Eurodollar 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, 2021 and 2020, Sierra Pacific had borrowings of $159 million and $45 million, respectively, outstanding under the credit facility. As of December 31, 2021 and 2020, the weighted average interest rate on borrowings outstanding was 0.86% and 0.90%, respectively. 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.

(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	2021	2020
General and refunding mortgage securities:			
3.375% Series T, due 2023	$ 250	$ 249	$ 249
2.600% Series U, due 2026	400	397	396
6.750% Series P, due 2037	252	253	255
Tax-exempt refunding revenue bond obligations:			
Fixed-rate series:			
1.850% Pollution Control Series 2016B, due 2029 (1)	30	30	29
3.000% Gas and Water Series 2016B, due 2036 (2)	60	60	61
0.625% Water Facilities Series 2016C, due 2036 (1)	30	30	30
2.050% Water Facilities Series 2016D, due 2036 (1)	25	25	25
2.050% Water Facilities Series 2016E, due 2036 (1)	25	25	25
2.050% Water Facilities Series 2016F, due 2036 (1)	75	75	74
1.850% Water Facilities Series 2016G, due 2036 (1)	20	20	20
Total long-term debt	$ 1,167	$ 1,164	$ 1,164
Reflected as -			
Long-term debt		$ 1,164	$ 1,164

(1) Subject to mandatory purchase by Sierra Pacific in April 2022 at which date the interest rate may be adjusted.

(2) Subject to mandatory purchase by Sierra Pacific in June 2022 at which date the interest rate may be adjusted.

Annual Payment on Long-Term Debt

The annual repayments of long-term debt for the years beginning January 1, 2022 and thereafter, are as follows (in millions):

2023	$ 250
2026	400
2027 and thereafter	517
Total	1,167
Unamortized premium, discount and debt issuance cost	(3)
Total	$ 1,164

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, 2021, approximately $4.5 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):

	2021	2020	2019
Current – Federal	$ 5	$ 3	$ 19
Deferred – Federal	13	12	10
Investment tax credits	—	—	(1)
Total income tax expense	$ 18	$ 15	$ 28

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:

	2021	2020	2019
Federal statutory income tax rate	21 %	21 %	21 %
Effects of ratemaking	(8)	(9)	—
Effective income tax rate	13 %	12 %	21 %

The net deferred income tax liability consists of the following as of December 31 (in millions):

	2021	2020
Deferred income tax assets:		
Regulatory liabilities	$ 64	$ 67
Operating and finance leases	27	30
Customer advances	14	10
Unamortized contract value	8	2
Other	6	8
Total deferred income tax assets	119	117
Deferred income tax liabilities:		
Property related items	(379)	(380)
Regulatory assets	(94)	(74)
Operating and finance leases	(27)	(30)
Other	(21)	(7)
Total deferred income tax liabilities	(521)	(491)
Net deferred income tax liability	$ (402)	$ (374)

The United States Internal Revenue Service has closed its examination of NV Energy's consolidated income tax returns through December 31, 2008, and effectively settled its examination of Sierra Pacific's income tax return for the short year ended December 31, 2013, and the statute of limitations has expired for NV Energy's consolidated income tax returns through the short year ended December 19, 2013. The closure or effective settlement of examinations, or the expiration of the statute of limitations may not preclude the Internal Revenue Service from adjusting the federal net operating loss carryforward utilized in a year for which the examination 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, 2021, 2020 and 2019. Sierra Pacific contributed $1 million to the Non-Qualified Pension Plans for the years ended December 31, 2021, 2020 and 2019. Sierra Pacific contributed $1 million to the Other Post Retirement Plan for the year ended December 31, 2021. Sierra Pacific did not make any contributions to the Other Post Retirement Plans for the years ended December 31, 2020 and 2019. 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):

	2021	2020
Qualified Pension Plan -		
Other non-current assets	$ 62	$ 26
Non-Qualified Pension Plans:		
Other current liabilities	(1)	(1)
Other long-term liabilities	(7)	(8)
Other Postretirement Plans -		
Other long-term liabilities	(10)	(13)

(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 $201 million and $197 million as of December 31, 2021 and 2020, respectively.

The following table presents Sierra Pacific's ARO liabilities by asset type as of December 31 (in millions):

	2021	2020
Asbestos	$ 5	$ 5
Evaporative ponds and dry ash landfills	3	3
Other	3	3
Total asset retirement obligations	$ 11	$ 11

The following table reconciles the beginning and ending balances of Sierra Pacific's ARO liabilities for the years ended December 31 (in millions):

	2021	2020
Beginning balance	$ 11	$ 10
Accretion	—	1
Ending balance	$ 11	$ 11
Reflected as -		
Other long-term liabilities	$ 11	$ 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, 2021:				
Not designated as hedging contracts [1]:				
Commodity assets	$ 2	$ —	$ —	$ 2
Commodity liabilities	—	(16)	(19)	(35)
Total derivative - net basis	$ 2	$ (16)	$ (19)	$ (33)
As of December 31, 2020:				
Not designated as hedging contracts[1]:				
Commodity assets	$ 9	$ —	$ —	$ 9
Commodity liabilities	—	—	(2)	(2)
Total derivative - net basis	$ 9	$ —	$ (2)	$ 7

(1) Sierra Pacific's commodity derivatives not designated as hedging contracts are included in regulated rates. As of December 31, 2021 a regulatory asset of $33 million was recorded related to the net derivative liability of $33 million. As of December 31, 2020 a regulatory liability of $7 million was recorded related to the net derivative asset of $7 million.

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	2021	2020
Electricity purchases	Megawatt hours	1	—
Natural gas purchases	Decatherms	53	54

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, 2021, Sierra Pacific's credit ratings for its senior secured debt and its issuer credit ratings for senior unsecured debt from the recognized credit rating agencies were investment grade.

The aggregate fair value of Sierra Pacific's derivative contracts in liability positions with specific credit-risk-related contingent features totaled $— million as of December 31, 2021 and 2020, 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, 2021:				
Assets:				
Commodity derivatives	$ —	$ —	$ 2	$ 2
Money market mutual funds	10	—	—	10
Investment funds	1	—	—	1
	$ 11	$ —	$ 2	$ 13
Liabilities - commodity derivatives	$ —	$ —	$ (35)	$ (35)
As of December 31, 2020:				
Assets:				
Commodity derivatives	$ —	$ —	$ 9	$ 9
Money market mutual funds	17	—	—	17
	$ 17	$ —	$ 9	$ 26
Liabilities - commodity derivatives	$ —	$ —	$ (2)	$ (2)

Sierra Pacific's investments in money market mutual funds and equity securities 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, 2021, 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.

Sierra Pacific's investments in money market mutual funds and equity securities 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.

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):

	2021	2020	2019
Beginning balance	$ 7	$ (1)	$ 2
Changes in fair value recognized in regulatory assets or liabilities	(25)	(2)	(5)
Settlements	(15)	10	2
Ending balance	$ (33)	$ 7	$ (1)

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):

	2021		2020	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 1,164	$ 1,316	$ 1,164	$ 1,358

(14) Commitments and Contingencies

Environmental Laws and Regulations

Sierra Pacific is subject to federal, state and local laws and regulations regarding air and water quality, renewable portfolio standards, emissions performance standards, climate change, coal combustion byproduct disposal, hazardous and solid waste disposal, protected species and other environmental matters that have the potential to impact Sierra Pacific's 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.

Commitments

Sierra Pacific has the following firm commitments that are not reflected on the Consolidated Balance Sheet. Minimum payments as of December 31, 2021 are as follows (in millions):

	2022	2023	2024	2025	2026	2027 and Thereafter	Total
Contract type:							
Fuel, capacity and transmission contract commitments	$ 338	$ 227	$ 149	$ 120	$ 105	$ 1,072	$ 2,011
Fuel and capacity contract commitments (not commercially operable)	25	27	27	26	26	459	590
Construction commitments	35	497	737	76	—	—	1,345
Easements	2	2	2	2	2	28	38
Maintenance, service and other contracts	7	6	6	5	1	—	25
Total commitments	$ 407	$ 759	$ 921	$ 229	$ 134	$ 1,559	$ 4,009

Fuel and Capacity Contract Commitments

Purchased Power

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 2022 to 2046. 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.

Coal and Natural Gas

Sierra Pacific has a long-term contract for the transport of coal that expires in 2024. Additionally, gas transportation contracts expire from 2023 to 2046 and the gas supply contracts expire from 2022 to 2023.

Fuel and Capacity Contract Commitments - Not 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.

Construction Commitments

Sierra Pacific's construction commitments included in the table above relate to firm commitments and include costs associated with two solar photovoltaic facility projects. The first project is a 250-MW solar photovoltaic facility with an additional 200 MWs of co-located battery storage that will be developed in Humboldt County, Nevada. Commercial operation is expected by the end of 2023. The second project is a 350-MW solar photovoltaic facility with an additional 280 MWs of co-located battery storage that will be developed in Humboldt County, Nevada. Commercial operation is expected by the end of 2024. Both facilities will be jointly owned and operated by Nevada Power and Sierra Pacific.

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, 2021, 2020 and 2019.

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 2026.

(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):

	2021			2020			2019		
	Electric	Natural Gas	Total	Electric	Natural Gas	Total	Electric	Natural Gas	Total
Customer Revenue:									
Retail:									
Residential	$ 307	$ 76	$ 383	$ 273	$ 76	$ 349	$ 268	$ 76	$ 344
Commercial	267	29	296	233	29	262	245	30	275
Industrial	202	10	212	170	9	179	186	10	196
Other	5	—	5	5	—	5	6	1	7
Total fully bundled	781	115	896	681	114	795	705	117	822
Distribution only service	3	—	3	4	—	4	4	—	4
Total retail	784	115	899	685	114	799	709	117	826
Wholesale, transmission and other	62	—	62	50	—	50	57	—	57
Total Customer Revenue	846	115	961	735	114	849	766	117	883
Other revenue	2	2	4	3	2	5	4	2	6
Total revenue	$ 848	$ 117	$ 965	$ 738	$ 116	$ 854	$ 770	$ 119	$ 889

(16) Supplemental Cash Flow Disclosures

Cash and Cash Equivalents and Restricted Cash and Cash Equivalents

Cash equivalents consist of funds invested in money market mutual funds, United States 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 as of December 31, 2021 and December 31, 2020, 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, 2021 and December 31, 2020, as presented in 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, 2021	December 31, 2020
Cash and cash equivalents	$ 10	$ 19
Restricted cash and cash equivalents included in other current assets	6	7
Total cash and cash equivalents and restricted cash and cash equivalents	$ 16	$ 26

The summary of supplemental cash flow disclosures as of and for the years ended December 31 is as follows (in millions):

	2021	2020	2019
Supplemental disclosure of cash flow information:			
Interest paid, net of amounts capitalized	$ 41	$ 42	$ 41
Income taxes (refunded) paid	$ (3)	$ 2	$ 37
Supplemental disclosure of non-cash investing and financing transactions:			
Accruals related to property, plant and equipment additions	$ 27	$ 17	$ 18

(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 totaled $2 million, $1 million and $1 million for the years ended December 31, 2021, 2020 and 2019.

Sierra Pacific provided electricity to Nevada Power of $43 million, $34 million and $25 million for the years ended December 31, 2021, 2020 and 2019, respectively. Receivables associated with these transactions were $— million and $1 million as of December 31, 2021 and 2020, respectively. Sierra Pacific purchased electricity from Nevada Power of $179 million, $106 million and $84 million for the years ended December 31, 2021, 2020 and 2019, respectively. Payables associated with these transactions were $13 million as of December 31, 2021 and 2020.

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, $5 million and $4 million for the years ending December 31, 2021, 2020 and 2019, respectively. Sierra Pacific provided services to Nevada Power of $15 million, $15 million, and $14 million for the years ended December 31, 2021, 2020 and 2019, respectively. Nevada Power provided services to Sierra Pacific of $25 million, $26 million, and $26 million for the years ended December 31, 2021, 2020 and 2019, respectively. As of December 31, 2021 and 2020, Sierra Pacific's Consolidated Balance Sheets included amounts due to NV Energy of $19 million and $17 million, respectively. There were no receivables due from NV Energy as of December 31, 2021 and 2020. As of December 31, 2021 and 2020, Sierra Pacific's Consolidated Balance Sheets included payables due to Nevada Power of $2 million. There were no receivables due from Nevada Power as of December 31, 2021 and 2020.

Sierra Pacific is party to a tax-sharing agreement with NV Energy and NV Energy is part of the Berkshire Hathaway consolidated United States federal income tax return. As of December 31, 2021 and 2020 federal income taxes receivable from NV Energy were $— million and $7 million, respectively. Sierra Pacific received cash refunds of $3 million for federal income taxes for the year ended December 31, 2021 and made cash payments of $2 million and $37 million for federal income taxes for the years ended December 31, 2020 and 2019, 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.

In January 2022, Sierra Pacific received a capital contribution of $130 million from NV Energy, Inc.

(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,		
	2021	2020	2019
Operating revenue:			
Regulated electric	$ 848	$ 738	$ 770
Regulated natural gas	117	116	119
Total operating revenue	$ 965	$ 854	$ 889
Operating income:			
Regulated electric	$ 148	$ 147	$ 150
Regulated natural gas	19	18	21
Total operating income	167	165	171
Interest expense	(54)	(56)	(48)
Allowance for borrowed funds	2	2	1
Allowance for equity funds	7	4	3
Interest and dividend income	9	4	3
Other, net	11	7	1
Income before income tax expense	$ 142	$ 126	$ 131

	As of December 31,		
	2021	2020	2019
Assets			
Regulated electric	$ 3,829	$ 3,540	$ 3,319
Regulated natural gas	365	342	308
Regulated common assets(1)	29	37	44
Total assets	$ 4,223	$ 3,919	$ 3,671

(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, 2021 was $262 million, an increase of $153 million, or 140%, compared to 2020, primarily due to a 2020 charge of $463 million associated with the probable abandonment of a significant portion of a project previously intended for EGTS to provide approximately 1,500,000 Dths of firm transportation service to various customers in connection with the Atlantic Coast Pipeline project ("Supply Header Project") and a 2020 charge of $141 million for cash flow hedges of debt-related items that were probable of not occurring as a result of the GT&S Transaction. These increases were partially offset by an increase in net income attributable to DEI's 50% noncontrolling interest in Cove Point of $226 million and the November 2020 disposition of Questar Pipeline Group of $75 million, both of which were a result of the GT&S Transaction, and income tax expense of $117 million in 2021 versus income tax benefit of $24 million in 2020, primarily due to higher pre-tax income.

Net income attributable to Eastern Energy Gas for the year ended December 31, 2020 was $109 million, a decrease of $612 million, or 85%, compared to 2019, primarily due to a charge associated with the probable abandonment of the Supply Header Project of $463 million, a charge for cash flow hedges of debt-related items that are probable of not occurring as a result of the GT&S Transaction of $141 million, interest income from Cove Point's notes receivable from DEI of $82 million recognized in 2019, a charge for disallowance of capitalized AFUDC due to the resolution of EGTS' 2015 FERC audit of $43 million and an increase in net income attributable to noncontrolling interests due to DEI's 50% interest in Cove Point effective with the GT&S Transaction of $39 million. These decreases are partially offset by interest expense of $100 million recognized in 2019 from Cove Point's term loan borrowings and income tax benefit of $24 million in 2020 versus income tax expense of $101 million in 2019, primarily due to lower pre-tax income.

Year Ended December 31, 2021 Compared to Year Ended December 31, 2020

Operating revenue decreased $220 million, or 11%, for 2021 compared to 2020, primarily due to the November 2020 disposition of Questar Pipeline Group of $197 million and a decrease in services performed for Atlantic Coast Pipeline of $43 million, which is offset in operations and maintenance expense, partially offset by an increase in regulated gas revenues for operational and system balancing purposes primarily due to increased prices of $15 million.

Cost of gas decreased $12 million, or 50%, for 2021 compared to 2020, primarily due to a favorable change in natural gas prices of $55 million and the November 2020 disposition of Questar Pipeline Group of $3 million, partially offset by an increase in prices of natural gas sold of $49 million.

Operations and maintenance decreased $627 million, or 55%, for 2021 compared to 2020, primarily due to a 2020 charge associated with the probable abandonment of the Supply Header Project of $463 million, a decrease in services performed for Atlantic Coast Pipeline of $45 million, the November 2020 disposition of Questar Pipeline Group of $43 million, a 2020 charge for disallowance of capitalized AFUDC due to the resolution of EGTS' 2015 FERC audit of $43 million, the 2020 write-off of certain items in connection with the GT&S Transaction of $17 million and a 2021 benefit from the finalization of entries for the disallowance of capitalized AFUDC of $11 million.

Depreciation and amortization decreased $38 million, or 10%, for 2021 compared to 2020, primarily due to the November 2020 disposition of Questar Pipeline Group.

Property and other taxes increased $9 million, or 6%, for 2021 compared to 2020, primarily due to higher tax assessments.

Interest expense decreased $188 million, or 55%, for 2021 compared to 2020, primarily due to a charge in 2020 for cash flow hedges of $141 million of debt-related items that were probable of not occurring as a result of the GT&S Transaction, the November 2020 disposition of Questar Pipeline Group of $16 million and lower interest expense of $17 million from the repayment of $700 million of long-term debt in the fourth quarter of 2020 and $5 million from the repayment of $500 million of long-term debt in the second quarter of 2021.

Allowance for borrowed funds decreased $4 million, or 67%, for 2021 compared to 2020, primarily due to the 2020 abandonment of the Supply Header Project.

Allowance for equity funds decreased $6 million, or 46%, for 2021 compared to 2020, primarily due to the 2020 abandonment of the Supply Header Project.

Interest and dividend income decreased $67 million for 2021 compared to 2020, primarily due to interest income from the East Ohio Gas Company of $33 million and DEI of $32 million recognized in 2020.

Other, net decreased $41 million, or 98%, for 2021 compared to 2020, primarily due to non-service cost credits recognized in 2020 related to certain Eastern Energy Gas benefit plans that were retained by DEI as a result of the GT&S Transaction.

Income tax expense (benefit) was an expense of $117 million for 2021 compared to a benefit of $24 million for 2020. The effective tax rate was 16% in 2021 and (12)% in 2020. The effective tax rate increased primarily due to the change in the noncontrolling interest of Cove Point as a result of the GT&S Transaction, lower pre-tax income driven by charges associated with the Supply Header Project in 2020 and the finalization of the effects from the change in tax status of certain Eastern Energy Gas subsidiaries in 2020.

Net income attributable to noncontrolling interests increased $226 million for 2021 compared to 2020, primarily due to DEI's 50% noncontrolling interest in Cove Point effective with the GT&S Transaction.

Year Ended December 31, 2020 Compared to Year Ended December 31, 2019

Operating revenue decreased $79 million, or 4%, for 2020 compared to 2019, primarily due to:

- $55 million decrease in services performed for Atlantic Coast Pipeline, which is offset in operations and maintenance expense;
- $45 million from the absence of Questar Pipeline Group operations from the date of the GT&S Transaction;
- $18 million from the absence of EGTS contract changes; and
- $14 million decrease in services provided to affiliates.

The decrease in operating revenue was offset by:

- $35 million increase in regulated gas sales primarily due to increased volumes; and
- $23 million from the absence of credits associated with the start-up phase of the Liquefaction Facility.

Cost of gas increased $15 million, or 167%, for 2020 compared to 2019, primarily due to an increase in volumes sold.

Operations and maintenance increased $394 million, or 53%, for 2020 compared to 2019, primarily due to a charge associated with the probable abandonment of the Supply Header Project of $463 million, a charge for disallowance of capitalized AFUDC due to the resolution of EGTS' 2015 FERC audit of $43 million and the write-off of certain items in connection with the GT&S Transaction of $17 million, partially offset by a decrease in services performed for Atlantic Coast Pipeline of $55 million, the absence of a charge related to a voluntary retirement program of $39 million, a decrease in services provided by affiliates of $16 million, the absence of a charge related to the abandonment of the Sweden Valley project of $13 million and the absence of Questar Pipeline Group operations from the date of the GT&S Transaction of $7 million.

Depreciation and amortization decreased $1 million for 2020 compared to 2019, primarily due to the absence of Questar Pipeline Group from the date of the GT&S Transaction of $8 million, partially offset by higher plant placed in-service of $7 million.

Property and other taxes decreased $1 million, or 1%, for 2020 compared to 2019, primarily due to the absence of Questar Pipeline Group operations from the date of the GT&S Transaction.

Interest expense increased $15 million, or 5%, for 2020 compared to 2019, primarily due to a charge in 2020 for cash flow hedges of $141 million of debt-related items that were probable of not occurring as a result of the GT&S Transaction and interest expense on Eastern Energy Gas' November 2019 senior note issuance of $23 million, partially offset by interest expense of $100 million recognized in 2019 from Cove Point's term loan borrowings that was repaid in September 2019, interest expense of $38 million recognized in 2019 from intercompany borrowings as a result of the Dominion Energy Gas Restructuring, the November 2020 disposition of Questar Pipeline Group of $3 million and lower interest expense of $3 million from the repayment of $700 million of long-term debt in the fourth quarter of 2020.

Allowance for borrowed funds decreased $7 million, or 54%, for 2020 compared to 2019, primarily due to lower capital expenditures related to the Supply Header Project as a result of the abandonment of the project.

Allowance for equity funds decreased $5 million, or 28%, for 2020 compared to 2019, primarily due to lower capital expenditures related to the Supply Header Project as a result of the abandonment of the project.

Interest and dividend income decreased $38 million, or 36%, for 2020 compared to 2019, primarily due to interest income from Cove Point's notes receivable from DEI of $82 million recognized in 2019 that was repaid in September 2019, partially offset by interest income from DEI of $27 million that was repaid in August 2020 and the East Ohio Gas Company of $20 million that was repaid in June 2020.

Income tax (benefit) expense decreased $125 million for 2020 compared to 2019. The effective tax rate was (12)% in 2020 and 13% in 2019. The effective tax rate decreased primarily due to the impact of lower pre-tax income of $552 million driven by charges associated with the Supply Header Project, partially offset by the effects of the changes in tax status in connection with the Dominion Energy Gas Restructuring of $24 million.

Net income attributable to noncontrolling interests increased $43 million, or 36%, for 2020 compared to 2019, primarily due to DEI's 50% noncontrolling interest in Cove Point effective with the GT&S Transaction.

Liquidity and Capital Resources

As of December 31, 2021, Eastern Energy Gas' total net liquidity was $422 million as follows (in millions):

Cash and cash equivalents	$ 22
Intercompany revolving credit agreement[1]	400
Total net liquidity	$ 422
Intercompany credit agreement:	
Maturity date	2022

(1) Refer to Note 20 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, 2021 and 2020 were $1.1 billion and $1.3 billion, respectively. The change was primarily due to lower collections from affiliates, the November 2020 disposition of Questar Pipeline Group and the timing of payments of operating costs, partially offset by the settlement of interest rate swaps in 2020 and higher income tax receipts.

Net cash flows from operating activities for the years ended December 31, 2020 and 2019 were $1.3 billion and $1.1 billion, respectively. The change was primarily due to changes in working capital offset by the settlement of interest rate swaps.

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 selected and assumptions made for each payment date.

Investing Activities

Net cash flows from investing activities for the years ended December 31, 2021 and 2020 were $(486) million and $3.1 billion, respectively. The change was primarily due to lower repayments of loans by affiliates of $3.1 billion, loans to affiliates of $183 million and higher funding of equity method investments of $152 million.

Net cash flows from investing activities for the years ended December 31, 2020 and 2019 were $3.1 billion and $1.2 billion, respectively. The change was primarily due to the absence of loans to affiliates of $1.9 billion and lower capital expenditures of $330 million, partially offset by lower repayments of loans by affiliates of $326 million.

Financing Activities

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.

Net cash flows from financing activities for the year ended December 31, 2020 were $(4.3) billion. Sources of cash totaled $1.2 billion and consisted of proceeds from equity contributions, that included a contribution from its indirect parent BHE to Eastern Energy Gas to repay its $700 million of debt. Uses of cash totaled $5.5 billion and consisted mainly of distributions of $4.5 billion, repayments of long-term debt of $700 million and net repayments of affiliated current borrowings of $251 million as required by the GT&S Transaction.

Net cash flows from financing activities for the year ended December 31, 2019 were $(2.4) billion. Sources of cash totaled $5.3 billion and consisted mainly of proceeds from equity contributions of $3.4 billion and proceeds from long-term debt issuances of $1.9 billion. Uses of cash totaled $7.7 billion and consisted mainly of repayments of long-term debt of $4.1 billion, net repayments of affiliated current borrowings of $2.8 billion and distributions of $636 million.

Short-term Debt

As of December 31, 2020, Eastern Energy Gas had $9 million of an outstanding note payable to an affiliate at a weighted average interest rate of 0.55%. For further discussion, refer to Note 20 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Long-term Debt

Eastern Energy Gas made repayments on long-term debt totaling $500 million and $700 million during the years ended December 31, 2021 and 2020, respectively.

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, 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. 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		
	2019[(1)]	2020	2021	2022	2023	2024
Natural gas transmission and storage	$ 105	$ 112	$ 16	$ 60	$ 133	$ 324
Other	289	262	426	297	274	251
Total	$ 394	$ 374	$ 442	$ 357	$ 407	$ 575

(1) Excludes capital expenditures related to entities disposed of in connection with the Dominion Energy Gas Restructuring. Refer to Note 3 of the Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for further discussion.

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 non-regulated 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, 2021, Eastern Energy Gas' investments that are accounted for under the equity method had short- and long-term debt of $310 million and an unused revolving credit facility of $10 million. As of December 31, 2021, Eastern Energy Gas' pro-rata share of such short- and long-term debt was $155 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, 2021 (in millions):

	Payments Due by Periods				
	2022	2023 - 2024	2025 - 2026	2027 and Thereafter	Total
Interest payments on long-term debt[(1)]	$ 139	$ 254	$ 174	$ 1,089	$ 1,656
Natural gas supply and transportation[(1)]	41	82	40	—	163
Total cash requirements	$ 180	$ 336	$ 214	$ 1,089	$ 1,819

(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 climate change, air and water quality, hazardous and solid waste disposal, protected species 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. Eastern Energy Gas 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. 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 structures administered by the FERC. Under these rate 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.

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 the 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 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 recognized in net income, returned to customers or re-established as AOCI. Total regulatory assets were $74 million and total regulatory liabilities were $685 million as of December 31, 2021. 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, 2021 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, 2021. Additionally, no indicators of impairment were identified as of December 31, 2021. 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 the asset that are used in the impairment analysis requires judgment regarding what Eastern Energy Gas would expect to recover from the future use of the asset. Changes in judgment that could significantly alter the calculation of the fair value or the recoverable amount of the asset may result from significant changes in the regulatory environment, the business climate, management's plans, legal factors, market price of the asset, the use of the asset or 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, if any, 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 continue to pass income tax benefits and expense related to the federal tax rate change from 35% to 21% as a result of 2017 Tax Reform, certain property-related basis differences and other various differences on to their customers. As of December 31, 2021, these amounts were recognized as a net regulatory liability of $468 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

Eastern Energy Gas is exposed to the impact of market fluctuations in commodity prices. Eastern Energy Gas is principally exposed to natural gas market fluctuations primarily through fuel retained and used during the operation of the pipeline system as well as lost and unaccounted for gas. Eastern Energy Gas is exposed to the risk of fuel retention, meaning customers have a fixed fuel retention percentage assessed on transportation and storage quantities, and the pipeline bears the risk of under-recovery and benefits from any over-recovery of volumes. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather, market liquidity, facility availability, customer usage, storage and transportation constraints. Eastern Energy Gas does not engage in proprietary trading activities. 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 quantities or sell future supply quantities generally at fixed prices. Eastern Energy Gas does not hedge all of its commodity price risk, thereby exposing the unhedged portion to changes in market prices.

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, 2021, Eastern Energy Gas had no short- or long-term variable-rate obligations that expose Eastern Energy Gas to the risk of increased interest expense in the event of increases in short-term interest rates. As of December 31, 2020, Eastern Energy Gas had short- and long-term variable-rate obligations totaling $509 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, 2020.

Eastern Energy Gas also uses interest rate derivatives, including forward starting swaps, interest rate swaps and interest rate lock agreements to manage interest rate risk. As of December 31, 2021, Eastern Energy Gas had no aggregate notional amounts of these interest rate swaps outstanding. As of December 31, 2020, Eastern Energy Gas had $500 million in aggregate notional amounts of these interest rate swaps outstanding. A hypothetical 10% decrease in market interest rates would not have a material effect on the fair value of Eastern Energy Gas' interest rate swaps as of December 31, 2020.

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, 2021 and 2020, 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, 2021 and 2020.

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 transportation 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, 2021, Eastern Energy Gas' credit exposure totaled $40 million. Of this amount, investment grade counterparties, including those internally rated, represented 92%, and no single counterparty, whether investment grade or non-investment grade, exceeded $6 million of exposure.

Item 8. Financial Statements and Supplementary Data

Report of Independent Registered Public Accounting Firm	415
Consolidated Balance Sheets	417
Consolidated Statements of Operations	419
Consolidated Statements of Comprehensive Income	420
Consolidated Statements of Changes in Equity	421
Consolidated Statements of Cash Flows	422
Notes to Consolidated Financial Statements	423

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, 2021 and 2020, 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, 2021, 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, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021, 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 — Impact of Rate Regulation on the Financial Statements — *Refer to Notes 2 and 6 to the financial statements*

Critical Audit Matter Description

Eastern Energy Gas, through its subsidiaries, is subject to rate regulation by the Federal Energy Regulatory Commission (the "FERC"), which has jurisdiction with respect to the rates of interstate natural gas transmission companies. Management has determined its rate regulated subsidiaries 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 economics of rate regulation impacts multiple financial statement line items and disclosures, such as property, plant, and equipment, net; regulatory assets; regulatory liabilities; operating revenue; operations and maintenance expense; and depreciation and amortization expense; and income tax expense (benefit).

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 impact of rate regulation as a critical audit matter due to the significant judgments made by management to support its assertions about impacted account balances and disclosures and the high degree of subjectivity involved in assessing the impact of future 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 future decisions by the FERC, auditing these judgments required specialized knowledge of the 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 impacts of rate regulation, including the balances recorded and regulatory developments.
- We read relevant regulatory orders issued by the FERC, regulatory statutes, interpretations, procedural memorandums, filings made by interveners, and other publicly available information 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 evaluated the external information and compared to management's recorded regulatory assets and liability balances for completeness.
- For regulatory matters in process, we inspected Eastern Energy Gas' filings with the FERC, and the filings with the FERC by intervenors that may impact Eastern Energy Gas' future rates for any evidence that might contradict management's assertions.
- We read and analyzed the minutes of the Board of Directors of Berkshire Hathaway Energy and the Board of Directors of Eastern Energy Gas, for discussions of changes in legal, regulatory, or business factors which could impact management's conclusions with respect to the impacted account balances and disclosures of rate regulation.

/s/ Deloitte & Touche LLP

Richmond, Virginia
February 25, 2022

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,	
	2021	**2020**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 22	$ 35
Restricted cash and cash equivalents	17	13
Trade receivables, net	183	177
Receivables from affiliates	54	139
Other receivables	9	51
Inventories	122	119
Prepayments	76	60
Natural gas imbalances	100	26
Other current assets	38	36
Total current assets	621	656
Property, plant and equipment, net	10,200	10,144
Goodwill	1,286	1,286
Investments	412	244
Other assets	129	291
Total assets	$ 12,648	$ 12,621

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, 2021	As of December 31, 2020
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 79	$ 71
Accounts payable to affiliates	38	39
Accrued interest	19	19
Accrued property, income and other taxes	89	29
Accrued employee expenses	13	23
Notes payable to affiliates	—	9
Regulatory liabilities	40	40
Asset retirement obligations	33	36
Current portion of long-term debt	—	500
Other current liabilities	54	48
Total current liabilities	365	814
Long-term debt	3,906	3,925
Regulatory liabilities	645	669
Other long-term liabilities	238	218
Total liabilities	5,154	5,626
Commitments and contingencies (Note 14)		
Equity:		
Members' equity:		
Membership interests	3,501	2,957
Accumulated other comprehensive loss, net	(43)	(53)
Total members' equity	3,458	2,904
Noncontrolling interests	4,036	4,091
Total equity	7,494	6,995
Total liabilities and equity	$ 12,648	$ 12,621

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,		
	2021	**2020**	**2019**
Operating revenue	$ 1,870	$ 2,090	$ 2,169
Operating expenses:			
Cost of gas	12	24	9
Operations and maintenance	515	1,142	748
Depreciation and amortization	328	366	367
Property and other taxes	149	140	141
Total operating expenses	1,004	1,672	1,265
Operating income	866	418	904
Other income (expense):			
Interest expense	(151)	(339)	(324)
Allowance for borrowed funds	2	6	13
Allowance for equity funds	7	13	18
Interest and dividend income	—	67	105
Other, net	1	42	43
Total other income (expense)	(141)	(211)	(145)
Income from continuing operations before income tax expense (benefit) and equity income	725	207	759
Income tax expense (benefit)	117	(24)	101
Equity income	44	42	43
Net income from continuing operations	652	273	701
Net income from discontinued operations[1]	—	—	141
Net income	652	273	842
Net income attributable to noncontrolling interests	390	164	121
Net income attributable to Eastern Energy Gas	$ 262	$ 109	$ 721

(1) Includes income tax expense of $33 million for the year ended December 31, 2019.

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,		
	2021	2020	2019
Net income	$ 652	$ 273	$ 842
Other comprehensive income (loss), net of tax:			
Unrecognized amounts on retirement benefits, net of tax of $—, $40 and $15	6	94	38
Unrealized gains (losses) on cash flow hedges, net of tax of $1, $10 and $(20)	9	30	(56)
Total other comprehensive income (loss), net of tax	15	124	(18)
Comprehensive income	667	397	824
Comprehensive income attributable to noncontrolling interests	395	154	120
Comprehensive income attributable to Eastern Energy Gas	$ 272	$ 243	$ 704

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)

	Predecessor Equity	Membership Interests	Accumulated Other Comprehensive Loss, Net	Noncontrolling Interests	Total Equity
Balance, December 31, 2018	$ 1,804	$ 4,566	$ (169)	$ 2,664	$ 8,865
Net income	232	489	—	121	842
Other comprehensive loss	—	—	(17)	(1)	(18)
Contributions	3,385	—	—	—	3,385
Distributions	(457)	—	—	(179)	(636)
Acquisition of public interest in Northeast Midstream	1,181	—	—	(1,221)	(40)
Dominion Energy Gas Restructuring	(6,145)	3,978	(1)	—	(2,168)
Other equity transactions	—	(2)	—	1	(1)
Balance, December 31, 2019	—	9,031	(187)	1,385	10,229
Net income	—	109	—	164	273
Other comprehensive income (loss)	—	—	134	(10)	124
Contributions	—	1,223	—	—	1,223
Distributions	—	(4,282)	—	(216)	(4,498)
Distribution of Questar Pipeline Group	—	(699)	—	—	(699)
Distribution of 50% interest in Cove Point	—	(2,765)	—	2,765	—
Acquisition of Eastern Energy Gas by BHE	—	343	—	—	343
Other equity transactions	—	(3)	—	3	—
Balance, December 31, 2020	—	2,957	(53)	4,091	6,995
Net income	—	262	—	390	652
Other comprehensive income	—	—	10	5	15
Contributions	—	419	—	—	419
Distributions	—	(137)	—	(450)	(587)
Balance, December 31, 2021	$ —	$ 3,501	$ (43)	$ 4,036	$ 7,494

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,		
	2021	2020	2019
Cash flows from operating activities:			
Net income	$ 652	$ 273	$ 842
Adjustments to reconcile net income to net cash flows from operating activities:			
(Gains) losses on other items, net	(3)	531	21
Depreciation and amortization	328	366	445
Allowance for equity funds	(7)	(13)	(18)
Equity loss, net of distributions	—	35	31
Changes in regulatory assets and liabilities	(20)	(37)	(74)
Deferred income taxes	186	(5)	(3)
Other, net	(19)	23	61
Changes in other operating assets and liabilities:			
Trade receivables and other assets	7	346	115
Derivative collateral, net	10	(140)	7
Pension and other postretirement benefit plans	—	(88)	(139)
Accrued property, income and other taxes	(30)	23	(53)
Accounts payable and other liabilities	(12)	(40)	(173)
Net cash flows from operating activities	1,092	1,274	1,062
Cash flows from investing activities:			
Capital expenditures	(442)	(374)	(704)
Loans to affiliates	(183)	—	(1,872)
Repayment of loans by affiliates	305	3,422	3,748
Equity method investments	(154)	(2)	(4)
Other, net	(12)	18	(18)
Net cash flows from investing activities	(486)	3,064	1,150
Cash flows from financing activities:			
Proceeds from long-term debt	—	—	1,895
Repayments of long-term debt	(500)	(700)	(4,141)
Net (repayments of) proceeds from short-term debt	—	(62)	52
Repayment of affiliated current borrowings, net	(9)	(251)	(2,837)
Credit facility repayments	—	—	(73)
Proceeds from equity contributions	346	1,223	3,385
Distributions to parent	—	(4,323)	(457)
Distributions to noncontrolling interests	(450)	(216)	(179)
Other, net	(2)	—	(16)
Net cash flows from financing activities	(615)	(4,329)	(2,371)
Net change in cash and cash equivalents and restricted cash	(9)	9	(159)
Cash and cash equivalents and restricted cash at beginning of period	48	39	198
Cash and cash equivalents and restricted cash at end of period	$ 39	$ 48	$ 39

The accompanying notes are an integral part of these 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 transportation pipeline and underground storage operations in the eastern region of the United States and operates Cove Point LNG, LP ("Cove Point"), a liquefied natural gas ("LNG") export, import and storage facility. Eastern Energy Gas owns 100% of the general partner interest and 25% of the limited partnership interest in Cove Point. 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 transportation pipeline. On November 1, 2020, Berkshire Hathaway Energy Company ("BHE") completed its acquisition of substantially all of the natural gas transmission and storage business of Dominion Energy, Inc. ("DEI") (the "GT&S Transaction"). As a result of the GT&S Transaction, Eastern Energy Gas became an indirect wholly owned subsidiary of 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"). See Note 3 for more information regarding the GT&S Transaction.

(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. 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 in 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 Equivalents and Restricted Cash and Cash Equivalents

Cash equivalents consist of funds invested in money market mutual funds, United States 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 amounts are included in restricted cash and cash equivalents on the Consolidated Balance Sheets.

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 the ability to exercise significant influence is restricted. In applying the equity method, Eastern Energy Gas records the investment at cost and subsequently increases or decreases the carrying value of the investment by Eastern Energy Gas' share of the net earnings or losses and other comprehensive income ("OCI") of the investee. Eastern Energy Gas records dividends or other equity distributions as reductions in the carrying value of the investment.

Allowance for Credit Losses

Trade receivables are primarily short-term in nature with stated collection terms of less than one year from the date of origination and are stated at the outstanding principal amount, net of an estimated allowance for credit losses. The allowance for credit losses is based on Eastern Energy Gas' assessment of the collectability of amounts owed to Eastern Energy Gas by its customers. This assessment requires judgment regarding the ability of customers to pay or the outcome of any pending disputes. In measuring the allowance for credit losses for trade receivables, Eastern Energy Gas primarily utilizes credit loss history. However, Eastern Energy Gas may adjust the allowance for credit losses to reflect current conditions and reasonable and supportable forecasts that deviate from historical experience. The changes in the balance of the allowance for credit losses, which is included in trades receivables, net on the Consolidated Balance Sheets, is summarized as follows for the years ended December 31, (in millions):

	2021	2020	2019
Beginning balance	$ 5	$ 2	$ —
Charged to operating costs and expenses, net	1	4	2
Write-offs, net	—	(1)	—
Ending balance	$ 6	$ 5	$ 2

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 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; and other, net for interest rate swap derivatives.

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.

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 current assets 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. See Note 6 for more information.

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. Prior to the GT&S Transaction, Eastern Energy Gas evaluated goodwill for impairment as of April 1. As a result of the GT&S Transaction, Eastern Energy Gas now completes its annual reviews as of October 31 to align with BHE's policy. 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 2021, 2020 and 2019, 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 what Eastern Energy Gas has the right to invoice as it corresponds directly with the value to the customer of Eastern Energy Gas' performance to date and includes billed and unbilled amounts. As of December 31, 2021 and 2020, trade receivables, net on the Consolidated Balance Sheets relate substantially to Customer Revenue, including unbilled revenue of $36 million and $95 million, respectively. Payments for amounts billed are generally due from the customer within 30 days of billing. Rates charged for energy products and services are established by regulators or contractual arrangements that establish the transaction price as well as the allocation of price amongst the separate performance obligations. When preliminary regulated rates are permitted to be billed prior to final approval by the applicable regulator, certain revenue collected may be subject to refund and a liability for estimated refunds is accrued. 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 $19 million and $29 million as of December 31, 2021 and 2020, respectively, and $18 million and $19 million of contract liabilities as of December 31, 2021 and 2020, respectively, due to Eastern Energy Gas' 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

Prior to the GT&S Transaction, DEI included Eastern Energy Gas in its consolidated United States federal income tax return. Subsequent to the GT&S Transaction, Berkshire Hathaway includes Eastern Energy Gas in its consolidated United States federal income tax return. Consistent with established regulatory practice, Eastern Energy Gas' provision for income taxes has been computed on a stand-alone return 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 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.

(3) Business Acquisitions and Dispositions

Acquisition of Eastern Energy Gas by BHE

In July 2020, DEI entered into an agreement to sell substantially all of its gas transmission and storage operations, including Eastern Energy Gas and a 25% limited partnership interest in Cove Point, to BHE. Approval of the transaction under the Hart-Scott-Rodino Act was not obtained within 75 days and DEI and BHE mutually agreed to a dual-phase closing consisting of two separate disposal groups identified as the GT&S Transaction and the proposed sale of Dominion Energy Questar Pipeline, LLC and related entities ("the Questar Pipeline Group") by DEI to BHE pursuant to a purchase and sale agreement entered into on October 5, 2020 ("Q-Pipe Transaction"). In July 2021, Dominion Energy Questar Corporation ("Dominion Questar") and DEI delivered a written notice to BHE stating that BHE and Dominion Questar mutually elected to terminate the Q-Pipe Transaction. Prior to the completion of the GT&S Transaction, Eastern Energy Gas finalized a restructuring whereby Eastern Energy Gas distributed the Questar Pipeline Group and a 50% noncontrolling interest in Cove Point to DEI. This restructuring was accounted for by Eastern Energy Gas as a reorganization of entities under common control and the disposition was reflected as an equity transaction. The disposition was not reported as a discontinued operation as the disposal did not represent a strategic shift in the way management had intended to run the business.

In November 2020, the GT&S Transaction was completed and Eastern Energy Gas, with the exception of the Questar Pipeline Group as discussed above, became an indirect wholly-owned subsidiary of BHE. DEI retained a 50% noncontrolling interest in Cove Point as well as the assets and obligations of the pension and other postretirement employee benefit plans associated with the operations sold and relating to services provided before closing. The GT&S Transaction was treated as a deemed asset sale for federal and state income tax purposes and all deferred taxes at Eastern Energy Gas were reset to reflect financial and tax basis differences as of November 1, 2020. See Notes 9 and 16 for more information on the GT&S Transaction.

Eastern Energy Gas recorded a distribution of net assets of $699 million, including goodwill of $185 million and $41 million of cash, for the distribution of the Questar Pipeline Group to DEI and recorded an approximately $2.8 billion increase in noncontrolling interests for DEI's retained 50% noncontrolling interest in Cove Point. Additionally, in accordance with the terms of the GT&S Transaction, DEI retained certain assets and liabilities associated with Eastern Energy Gas and settled all affiliated balances. As a result, Eastern Energy Gas recorded a contribution for the reset of deferred taxes of $1.3 billion, net of distributions of $895 million related to the pension and other postretirement employee benefit plans retained by DEI and $107 million related to the settlement of affiliated balances.

Dominion Energy Gas Restructuring

The acquisition of CPMLP Holdings Company, LLC ("DCP") and Eastern MLP Holding Company II, LLC ("DMLPHCII") from, and the disposition of the East Ohio Gas Company ("East Ohio") and Eastern Gathering and Processing, Inc. ("EGP") to, DEI by Eastern Energy Gas on November 6, 2019 ("Dominion Energy Gas Restructuring") was considered to be a reorganization of entities under common control. As a result, Eastern Energy Gas' basis in DCP and DMLPHCII, which included the general partner of Northeast Midstream Partners, LP ("Northeast Midstream"), a controlling 75% interest in Cove Point, Carolina Gas Transmission, LLC, Questar Pipeline Group, a 50% noncontrolling interest in White River Hub, LLC ("White River Hub") and a 25.93% noncontrolling interest in Iroquois, is equal to DEI's cost basis in the assets and liabilities of such entities since the applicable inception dates of common control. In November 2019, following completion of the Dominion Energy Gas Restructuring, DCP and DMLPHCII are wholly-owned subsidiaries of Eastern Energy Gas and therefore are consolidated by Eastern Energy Gas. The accompanying Consolidated Financial Statements and Notes of Eastern Energy Gas have been retrospectively adjusted to include the historical results and financial position of DCP and DMLPHCII. The 25% interest in Cove Point retained by DEI, and subsequently sold to Brookfield Super-Core Infrastructure Partners ("Brookfield") in December 2019, and the non-DEI held interest in Northeast Midstream (through January 2019) are reflected as noncontrolling interest.

The Dominion Energy Gas Restructuring included the disposition of East Ohio and EGP by Eastern Energy Gas in November 2019. This restructuring represented a strategic shift in the operations of Eastern Energy Gas as Eastern Energy Gas' operations consist of LNG import/export and storage and regulated gas transmission and storage operations. As a result, the accompanying Consolidated Financial Statements and Notes of Eastern Energy Gas have been retrospectively adjusted to include the historical results and financial position of East Ohio and EGP as discontinued operations until November 2019. As the Dominion Energy Gas Restructuring was considered to be a reorganization of entities under common control, Eastern Energy Gas reflected the disposition as an equity transaction. The following table represents selected information regarding the results of operations of East Ohio, which are reported as discontinued operations in Eastern Energy Gas' Consolidated Statements of Operations (in millions):

		Period Ended November 6, 2019
Operating revenue	$	594
Depreciation and amortization		73
Other operating expenses		399
Other income (expense), net		28
Income tax expense		26
Net income from discontinued operations	$	124

Capital expenditures and significant noncash items relating to East Ohio included the following (in millions):

		Period Ended November 6, 2019
Capital expenditures	$	299
Significant noncash items:		
Charge related to a voluntary retirement program		20
Accrued capital expenditures		2

The following table represents selected information regarding the results of operations of EGP, which are reported as discontinued operations in Eastern Energy Gas' Consolidated Statements of Operations (in millions):

		Period Ended November 6, 2019
Operating revenue	$	125
Depreciation and amortization		4
Other operating expenses		97
Income tax expense		7
Net income from discontinued operations	$	17

Capital expenditures of EGP included the following (in millions):

		Period Ended November 6, 2019
Capital expenditures	$	11

(4) Property, Plant and Equipment, Net

Property, plant and equipment, net consists of the following as of December 31 (in millions):

	Depreciable Life	2021	2020
Utility Plant:			
Interstate natural gas pipeline assets	21 - 44 years	$ 8,675	$ 8,382
Intangible plant	5 - 10 years	110	115
Utility plant in-service		8,785	8,497
Accumulated depreciation and amortization		(2,901)	(2,759)
Utility plant in-service, net		5,884	5,738
Nonutility Plant:			
LNG facility	40 years	4,475	4,454
Intangible plant	14 years	25	25
Nonutility plant in-service		4,500	4,479
Accumulated depreciation and amortization		(423)	(283)
Nonutility plant in-service, net		4,077	4,196
Plant, net		9,961	9,934
Construction work- in-progress		239	210
Property, plant and equipment, net		$ 10,200	$ 10,144

Construction work-in-progress includes $209 million and $196 million as of December 31, 2021 and 2020, respectively, related to the construction of utility plant.

(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, 2021 (dollars in millions):

	Eastern Energy Gas' Share	Facility in Service	Accumulated Depreciation and Amortization	Construction Work-in-Progress
Ellisburg Pool	39 %	$ 31	$ 11	$ 1
Ellisburg Station	50	26	8	1
Harrison	50	53	18	—
Leidy	50	132	46	7
Oakford	50	200	68	2
Total		$ 442	$ 151	$ 11

(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	2021	2020
Employee benefit plans[1]	14 years	$ 62	$ 70
Other	Various	12	12
Total regulatory assets		$ 74	$ 82
Reflected as:			
Other current assets		$ 6	$ 8
Other assets		68	74
Total regulatory assets		$ 74	$ 82

(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 $8 million and $10 million as of December 31, 2021 and 2020, 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	2021	2020
Income taxes refundable through future rates[1]	Various	$ 468	$ 473
Other postretirement benefit costs[2]	Various	116	115
Cost of removal[3]	44 years	73	88
Other	Various	28	33
Total regulatory liabilities		$ 685	$ 709
Reflected as:			
Current liabilities		$ 40	$ 40
Noncurrent liabilities		645	669
Total regulatory liabilities		$ 685	$ 709

(1) Amounts primarily represent income tax liabilities related to the federal tax rate change from 35% to 21% that are probable to be passed on to customers, offset by income tax benefits related to certain property-related basis differences and other various differences that were previously passed on to customers and will be included in regulated rates when the temporary differences reverse.

(2) Reflects a regulatory liability for the collection of postretirement benefit costs allowed in rates in excess of expense incurred.

(3) Amounts represent estimated costs, as accrued through depreciation rates and exclusive of ARO liabilities, of removing regulated property, plant and equipment in accordance with accepted regulatory practices.

Regulatory Matters

Eastern Gas Transmission and Storage, Inc.

In September 2021, Eastern Gas Transmission and Storage, Inc. ("EGTS") filed a general rate case for its FERC-jurisdictional services, with proposed rates to be effective November 1, 2021. EGTS' previous general rate case was settled in 1998. 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 transportation 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 and the outcome of hearing procedures. This matter is pending.

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) charge for disallowance of capitalized AFUDC, recorded within operations and maintenance expense in the Consolidated Statement of Operations. 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 operations and maintenance expense in the Consolidated Statement of Operations in the second quarter of 2021. In September 2021, the FERC approved EGTS' accounting entries and supporting documentation.

In December 2014, EGTS entered into a precedent agreement with Atlantic Coast Pipeline, LLC ("Atlantic Coast Pipeline") for the project previously intended for EGTS to provide approximately 1,500,000 decatherms ("Dth") of firm transportation service to various customers in connection with the Atlantic Coast Pipeline project ("Supply Header Project"). As a result of the cancellation of the Atlantic Coast Pipeline project, in the second quarter of 2020 Eastern Energy Gas recorded a charge of $482 million ($359 million after-tax) in operations and maintenance expense in its Consolidated Statement of Operations associated with the probable abandonment of a significant portion of the project as well as the establishment of a $75 million ARO. In the third quarter of 2020, Eastern Energy Gas recorded an additional charge of $10 million ($7 million after-tax) associated with the probable abandonment of a significant portion of the project and a $29 million ($20 million after-tax) benefit from a revision to the previously established ARO, both of which were recorded in operations and maintenance expense in Eastern Energy Gas' Consolidated Statement of Operations. As EGTS evaluates its future use, approximately $40 million remains within property, plant and equipment for a potential modified project.

In January 2018, EGTS filed an application to request FERC authorization to construct and operate certain facilities located in Ohio and Pennsylvania for the Sweden Valley project. In June 2019, EGTS withdrew its application for the project due to certain regulatory delays. As a result of the project abandonment, during the second quarter of 2019, EGTS recorded a charge of $13 million ($10 million after-tax), included in operations and maintenance expenses in the Consolidated Statement of Operations.

Cove Point

In January 2020, pursuant to the terms of a previous settlement, Cove Point filed a general rate case for its FERC-jurisdictional services, with proposed rates to be effective March 1, 2020. Cove Point proposed an annual cost-of-service of $182 million. In February 2020, FERC approved suspending the changes in rates for five months following the proposed effective date, until August 1, 2020, subject to refund. In November 2020, Cove Point reached an agreement in principle with the active participants in the general rate case proceeding. Under the terms of the agreement in principle, Cove Point's rates effective August 1, 2020 result in an increase to annual revenues of $4 million and a decrease in annual depreciation expense of $1 million, compared to the rates in effect prior to August 1, 2020. The interim settlement rates were implemented November 1, 2020, and Cove Point's provision for rate refunds for August 2020 through October 2020 totaled $7 million. The agreement in principle was reflected in a stipulation and agreement filed with the FERC in January 2021. In March 2021, the FERC approved the stipulation and agreement and the rate refunds to customers were processed in late April 2021.

(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):

	2021	2020
Investments:		
Investment funds	$ 13	$ —
Equity method investments:		
Iroquois	399	244
Total investments	412	244
Restricted cash and cash equivalents:		
Customer deposits	17	13
Total restricted cash and cash equivalents	17	13
Total investments and restricted cash and cash equivalents	$ 429	$ 257
Reflected as:		
Current assets	$ 17	$ 13
Noncurrent assets	412	244
Total investments and restricted cash and cash equivalents	$ 429	$ 257

Equity Method Investments

Eastern Energy Gas, through a subsidiary, owns 50% of Iroquois, which owns and operates an interstate natural gas pipeline located in the states of New York and Connecticut. Prior to the GT&S Transaction, Eastern Energy Gas, through the Questar Pipeline Group, owned 50% of White River Hub, which owns and operates a natural gas pipeline in northwest Colorado.

As of both December 31, 2021 and 2020, 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 $44 million, $77 million and $74 million for the years ended December 31, 2021, 2020 and 2019, respectively.

(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 in 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	2021	2020
Eastern Energy Gas:			
Variable-rate Senior Notes, due 2021[1]	$ —	$ —	$ 500
2.875% Senior Notes, due 2023	250	250	249
3.55% Senior Notes, due 2023	400	399	399
2.50% Senior Notes, due 2024	600	597	596
3.60% Senior Notes, due 2024	339	338	448
3.32% Senior Notes, due 2026 (€250)[2]	284	283	304
3.00% Senior Notes, due 2029	174	173	594
3.80% Senior Notes, due 2031	150	150	150
4.80% Senior Notes, due 2043	54	53	395
4.60% Senior Notes, due 2044	56	56	493
3.90% Senior Notes, due 2049	27	26	297
EGTS:			
3.60% Senior Notes, due 2024	111	110	—
3.00% Senior Notes, due 2029	426	422	—
4.80% Senior Notes, due 2043	346	341	—
4.60% Senior Notes, due 2044	444	437	—
3.90% Senior Notes, due 2049	273	271	—
Total long-term debt	$ 3,934	$ 3,906	$ 4,425
Reflected as:			
Current portion of long-term debt		$ —	$ 500
Long-term debt		3,906	3,925
Total long-term debt		$ 3,906	$ 4,425

(1) The senior notes had variable interest rates based on LIBOR plus an applicable spread. Eastern Energy Gas entered into an interest rate swap that fixed the interest rate on 100% of the notes. The fixed interest rate as of December 31, 2020 was 3.46% (including a 0.60% margin).

(2) 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, 2021 and 2020 that averaged 3.32%.

Annual Payment on Long-Term Debt

The annual repayments of long-term debt for the years beginning January 1, 2022 and thereafter, are as follows (in millions):

2022	$ —
2023	650
2024	1,050
2025	—
2026	284
2027 and thereafter	1,950
Total	3,934
Unamortized premium, discount and debt issuance cost	(28)
Total	$ 3,906

(9) Income Taxes

Income tax expense (benefit) consists of the following for the years ended December 31 (in millions):

	2021	2020	2019
Current:			
Federal	$ (47)	$ (20)	$ 130
State	(21)	1	17
	(68)	(19)	147
Deferred:			
Federal	129	23	(36)
State	56	(28)	(10)
	185	(5)	(46)
Total	$ 117	$ (24)	$ 101

Income tax expense reported in discontinued operations for the year ended December 31, 2019 was $33 million.

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:

	2021	2020	2019
Federal statutory income tax rate	21 %	21 %	21 %
State income tax, net of federal income tax benefit	3	(13)	1
Equity interest	1	4	1
Effects of ratemaking	1	(2)	(1)
Change in tax status	—	(9)	(4)
AFUDC-equity	—	(1)	(1)
Noncontrolling interest	(11)	(16)	(3)
Write-off of regulatory assets	—	3	—
Other, net	1	1	(1)
Effective income tax rate	16 %	(12)%	13 %

For the year ended December 31, 2021, 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 GT&S Transaction resulted in a change of Cove Point's noncontrolling interest from 25% to 75% as of November 1, 2020.

The net deferred income tax (liability) asset consists of the following as of December 31 (in millions):

	2021	2020
Deferred income tax assets:		
Federal and state carryforwards	$ 7	$ —
Employee benefits	33	30
Intangibles	150	148
Derivatives and hedges	16	18
Other	9	4
Total deferred income tax assets	215	200
Deferred income tax liabilities:		
Property related items	(129)	(52)
Partnership investments	(49)	(19)
Debt exchange	(60)	—
Deferred state income taxes	(16)	—
Debt issuance discount	(7)	(8)
Other	(9)	(2)
Total deferred income tax liabilities	(270)	(81)
Net deferred income tax (liability) asset [(1)]	$ (55)	$ 119

(1) Net deferred income tax liability as of December 31, 2021 is presented in other assets and other long-term liabilities in the Consolidated Balance Sheet. Net deferred income tax asset as of December 31, 2020 is presented in other assets in the Consolidated Balance Sheet.

The significant change in net deferred taxes is due to higher tax depreciation due to the GT&S Transaction being treated as a deemed asset sale for federal and state income tax purposes, the debt exchange at EGTS and partnership income from Cove Point.

As of December 31, 2021, Eastern Energy Gas' $7 million of state net operating losses, entirely related to West Virginia, can be carried forward indefinitely.

Through October 31, 2020, Eastern Energy Gas was included in DEI's consolidated federal income tax return and, where applicable, combined state income tax returns. As a result of the GT&S Transaction, DEI retained the rights and obligations of Eastern Energy Gas' federal and state income tax returns through October 31, 2020. The statute of limitations for Eastern Energy Gas' income tax returns filed for periods after November 1, 2020 remain open for examination for federal and Connecticut, Maryland, North Carolina, Pennsylvania, South Carolina, Virginia, and West Virginia.

A reconciliation of the beginning and ending balances of Eastern Energy Gas' net unrecognized tax benefits is as follows for the years ended December 31 (in millions):

	2021	2020
Beginning balance	$ —	$ 2
Additions for tax positions of prior years	—	5
Reductions for unrecognized tax benefits retained by DEI	—	(7)
Ending balance	$ —	$ —

As of December 31, 2021, Eastern Energy Gas has no unrecognized tax benefits that would have an impact on the effective tax rate. As part of the GT&S Transaction, DEI has retained all pre-close unrecognized tax benefits.

(10) Employee Benefit Plans

As discussed in Note 3, in November 2020, the GT&S Transaction was completed and the assets and obligations of the pension and other postretirement employee benefit plans associated with the operations sold and relating to services provided before closing were retained by DEI. As a result, just prior to completing the sale, net benefit plan assets of $895 million were distributed through an equity transaction with DEI.

Subsequent to the GT&S Transaction

Subsequent to the GT&S Transaction, 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 $18 million and $3 million of contributions to the MidAmerican Energy Company Retirement Plan for the years ended December 31, 2021 and 2020, respectively. Eastern Energy Gas made $10 million and $2 million of contributions to the MidAmerican Energy Company Welfare Benefit Plan for the years ended December 31, 2021 and 2020, respectively. 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.

Eastern Energy Gas participates in the BHE GT&S, LLC ("BHE GT&S") defined contribution employee savings plan subsequent to the GT&S Transaction. Eastern Energy Gas' matching contributions are based on each participant's level of contribution. Contributions cannot exceed the maximum allowable for tax purposes. Eastern Energy Gas' contributions to the 401(k) plan were $5 million and $1 million for the years ended December 31, 2021 and 2020, respectively.

Prior to the GT&S Transaction

Defined Benefit Plans

Prior to the GT&S Transaction, certain Eastern Energy Gas employees not represented by collective bargaining units were covered by the Dominion Energy Pension Plan, a defined benefit pension plan sponsored by DEI that provides benefits to multiple DEI subsidiaries. As participating employers, Eastern Energy Gas was subject to DEI's funding policy, which was to contribute annually an amount that is in accordance with the Employee Retirement Income Security Act of 1974. Eastern Energy Gas' net periodic pension credit related to this plan was $(14) million and $(8) million for the years ended December 31, 2020 and 2019, respectively. Net periodic pension (credit) cost is reflected in other operations and maintenance expense in the Consolidated Statements of Operations, except for $(14) million of Eastern Energy Gas' costs for the year ended December 31, 2019 that are recorded in net income from discontinued operations. The funded status of various DEI subsidiary groups and employee compensation are the basis for determining the share of total pension costs for participating DEI subsidiaries.

Prior to the GT&S Transaction, certain retiree healthcare and life insurance benefits for Eastern Energy Gas employees not represented by collective bargaining units were covered by the Dominion Energy Retiree Health and Welfare Plan, a plan sponsored by DEI that provides certain retiree healthcare and life insurance benefits to multiple DEI subsidiaries. Eastern Energy Gas' net periodic benefit credit related to this plan was $(5) million and $(4) million for the years ended December 31, 2020 and 2019, respectively. Net periodic benefit (credit) cost is reflected in other operations and maintenance expense in the Consolidated Statements of Operations, except for less than $(1) million of Eastern Energy Gas' costs for the year ended December 31, 2019 that are recorded in net income from discontinued operations. Employee headcount is the basis for determining the share of total other postretirement benefit costs for participating DEI subsidiaries.

Pension benefits for Eastern Energy Gas employees represented by collective bargaining units were covered by a separate pension plan that provides benefits to employees of both EGTS and Hope Gas, Inc. ("Hope"). Employee compensation was the basis for allocating pension costs and obligations between EGTS and Hope. Retiree healthcare and life insurance benefits for Eastern Energy Gas employees represented by collective bargaining units were covered by a separate other postretirement benefit plan that provides benefits to both EGTS and Hope. Employee headcount was the basis for allocating other postretirement benefit costs and obligations between EGTS and Hope.

Eastern Energy Gas included the separate pension and other postretirement benefit plans for East Ohio employees covered by collective bargaining units through November 2019, the effective date of the Dominion Energy Gas Restructuring. See Note 3 for more information on the Dominion Energy Gas Restructuring.

Pension Remeasurement

In the third quarter of 2020, Eastern Energy Gas remeasured a pension plan due to a curtailment resulting from the agreement for DEI to retain the assets and obligations of the pension benefit plan associated with the GT&S Transaction. The remeasurement resulted in an increase in the pension benefit obligation of $3 million and a decrease in the fair value of the pension plan assets of $7 million for Eastern Energy Gas. The impact of the remeasurement on net periodic pension benefit credit was recognized prospectively from the remeasurement date and was not material. The discount rate used for the remeasurement was 3.16%. All other assumptions used for the remeasurement were consistent with the measurement as of December 31, 2019.

Voluntary Retirement Program

In March 2019, Eastern Energy Gas announced a voluntary retirement program to employees that met certain age and service requirements. The voluntary retirement program will not compromise safety or Eastern Energy Gas' ability to comply with applicable laws and regulations. In 2019, upon the determinations made concerning the number of employees that elected to participate in the program, Eastern Energy Gas recorded a charge of $74 million ($58 million after-tax) included within operations and maintenance expense ($41 million), other income ($1 million) and discontinued operations ($32 million) in the Consolidated Statements of Operations.

In the second quarter of 2019, Eastern Energy Gas remeasured its pension and other postretirement benefit plans as a result of the voluntary retirement program. The impact of the remeasurement on net periodic benefit cost (credit) was recognized prospectively from the remeasurement date. The discount rate used for the remeasurement was 4.10% for the Eastern Energy Gas pension plans and 4.05% for the Eastern Energy Gas other postretirement benefit plans. All other assumptions used for the remeasurement were consistent with the measurement as of December 31, 2018.

Net Periodic Benefit Credit

Net periodic benefit credit for the plans included the following components for the years ended December 31 (in millions):

	Pension		**Other Postretirement**	
	2020	**2019**	**2020**	**2019**
Service cost	$ 5	$ 6	$ 1	$ 1
Interest cost	8	11	4	5
Expected return on plan assets	(47)	(54)	(16)	(16)
Settlement	—	1	—	1
Net amortization	5	7	(3)	(2)
Net periodic benefit credit	$ (29)	$ (29)	$ (14)	$ (11)

Significant assumptions used to determine periodic credits for the years ended December 31:

	Pension		Other Postretirement	
	2020	2019	2020	2019
Discount rate	3.16% - 3.63%	4.10% - 4.42%	3.44 %	4.05% - 4.37%
Expected long-term rate of return on plan assets	8.60 %	8.65 %	8.50 %	8.50 %
Weighted average rate of increase for compensation	4.73 %	4.55 %	N/A	N/A
Healthcare cost trend rate			6.50 %	6.50 %
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)			5.00 %	5.00 %
Year that the rate reached the ultimate trend rate			2026	2025

Defined Contribution Plans

Eastern Energy Gas participated in the DEI defined contribution employee savings plans prior to the GT&S Transaction. Eastern Energy Gas' matching contributions were based on each participant's level of contribution. Contributions could not exceed the maximum allowable for tax purposes. Eastern Energy Gas' contributions to the 401(k) plan were $3 million and $4 million for the years ended December 31, 2020 and 2019, 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 $73 million and $88 million as of December 31, 2021 and 2020, 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):

	2021	2020
Beginning balance	$ 71	$ 89
Change in estimated costs	—	(51)
Additions	—	48
Retirements	(17)	(3)
Disposal of Questar Pipeline Group	—	(16)
Accretion	1	4
Ending balance	$ 55	$ 71
Reflected as:		
Current liabilities	$ 33	$ 36
Other long-term liabilities	22	35
Total ARO liability	$ 55	$ 71

(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 as well as lost and unaccounted for gas, to interest rate risk on its outstanding variable-rate short- and long-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.

Subsequent to the GT&S Transaction, Eastern Energy Gas has elected to offset derivative contracts where master netting arrangements allow. There have been no other 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 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	2021	2020
Interest rate	U.S. $	—	500
Foreign currency	Euro €	250	250
Natural gas	Dth	2	5

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 transportation 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 40% and 34% of Eastern Energy Gas' operating revenues for the years ended December 31, 2021 and 2020, respectively, with Eastern Energy Gas' largest customer representing approximately 20% and 17% of such amounts.

For the year ended December 31, 2021, EGTS provided service to 278 customers with approximately 98% of its storage and transportation revenue being provided through firm services. The 10 largest customers provided approximately 38% of the total storage and transportation revenue and the thirty largest provided approximately 71% of the total storage and transportation 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, 2021				
Assets:				
Foreign currency exchange rate derivatives	$ —	$ 3	$ —	$ 3
Investment funds	13	—	—	13
	$ 13	$ 3	$ —	$ 16
Liabilities:				
Foreign currency exchange rate derivatives	$ —	$ (3)	$ —	$ (3)
	$ —	$ (3)	$ —	$ (3)
As of December 31, 2020				
Assets:				
Foreign currency exchange rate derivatives	$ —	$ 20	$ —	$ 20
	$ —	$ 20	$ —	$ 20
Liabilities:				
Commodity derivatives	$ —	$ (1)	$ —	$ (1)
Foreign currency exchange rate derivatives	—	(2)	—	(2)
Interest rate derivatives	—	(6)	—	(6)
	$ —	$ (9)	$ —	$ (9)

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 carrying value of Eastern Energy Gas' 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 Eastern Energy Gas' long-term debt as of December 31 (in millions):

	2021		2020	
	Carrying Value	**Fair Value**	**Carrying Value**	**Fair Value**
Long-term debt	$ 3,906	$ 4,266	$ 4,425	$ 5,012

(14) Commitments and Contingencies

Environmental Laws and Regulations

Eastern Energy Gas is subject to federal, state and local laws and regulations regarding climate change, renewable portfolio standards, air and water quality, emissions performance standards, hazardous and solid waste disposal, protected species and other environmental matters that have the potential to impact Eastern Energy Gas' current and future operations. Eastern Energy Gas believes it is in material compliance with all applicable laws and regulations.

Air

Revisions to Ozone National Ambient Air Quality Ozone Standards

The Clean Air Act includes National Ambient Air Quality Standards ("NAAQS"). States adopt rules that ensure their air quality meets the NAAQS. In October 2015, the United States Environmental Protection Agency ("EPA") published a rule lowering the ground level ozone NAAQS for non-attainment designations. States had until August 2021 to develop plans to address the new standard, which did not result in a material impact on Eastern Energy Gas' results of operations and cash flows. 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 Eastern Energy Gas, the EPA must, by April 30, 2022, approve or disapprove the interstate ozone state implementation plans of Maryland, New York, Ohio, Pennsylvania and West Virginia. Also in January 2022, the EPA initiated interagency review of a new rule to address "good neighbor" state implementation plan provisions. While the interagency review is not yet complete and the proposed rule is not available for public comment, the EPA has indicated that the action would apply in certain states for which the EPA has either disapproved a "good neighbor" state implementation plan submission or has made a finding of failure to submit such a plan for the 2015 ozone NAAQS. The action would determine whether and to what extent ozone-precursor emissions reductions are required to eliminate significant contribution or interference with maintenance from upwind states that are linked to air quality problems in other states for the 2015 standard. Until the EPA takes final action consistent with this decree, Eastern Energy Gas cannot predict the impact to its results of operations, financial condition and/or cash flows.

Oil and Gas New Source Performance Standards

In August 2020, the EPA issued two final amendments related to the reconsideration of the New Source Performance Standard ("NSPS") for the oil and natural gas sector applicable to volatile organic compound and methane emissions. Together, the two amendments have the effect of rescinding the methane portion of the NSPS for all segments of the oil and natural gas sector, rescinding all NSPS for the transmission and storage segment and modifying some of the NSPS volatile organic compound requirements for facilities in the production and processing segments. 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 emissions 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 intends to issue a supplemental proposal in 2022, including draft regulatory text, and plans to finalize the rules by the end of 2022. Until the EPA ultimately takes final action on this rulemaking, Eastern Energy Gas cannot predict the impact to its results of operations, financial condition and/or cash flows.

Carbon Regulations

In August 2016, the EPA issued a draft rule proposing to reaffirm that a source's obligation to obtain a prevention of significant deterioration or Title V permit for greenhouse gases ("GHG") is triggered only if such permitting requirements are first triggered by non-GHG, or conventional, pollutants that are regulated by the New Source Review program, and to set a significant emissions rate at 75,000 tons per year of carbon dioxide equivalent emissions under which a source would not be required to apply best available control technology for its GHG emissions. Until the EPA ultimately takes final action on this rulemaking, Eastern Energy Gas cannot predict the impact to its results of operations, financial condition and/or cash flows.

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, 2021, Eastern Energy Gas had purchased $19 million of surety bonds. Under the terms of 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):

	2021	2020	2019
Customer Revenue:			
Regulated:			
Gas transportation and storage	$ 1,044	$ 1,242	$ 1,300
Wholesale	57	43	9
Other	(2)	4	7
Total regulated	1,099	1,289	1,316
Nonregulated	767	798	849
Total Customer Revenue	1,866	2,087	2,165
Other revenue	4	3	4
Total operating revenue	$ 1,870	$ 2,090	$ 2,169

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, 2021 (in millions):

	Performance obligations expected to be satisfied		
	Less than 12 months	More than 12 months	Total
Eastern Energy Gas	$ 1,594	$ 16,126	$ 17,720

(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
Balance, December 31, 2018	$ (144)	$ (25)	$ —	$ (169)
Other comprehensive income (loss)	38	(56)	—	(18)
Balance, December 31, 2019	(106)	(81)	—	(187)
Other comprehensive income	94	30	10	134
Balance, December 31, 2020	(12)	(51)	10	(53)
Other comprehensive income (loss)	6	9	(5)	10
Balance, December 31, 2021	$ (6)	$ (42)	$ 5	$ (43)

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
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	
2020		
Deferred (gains) and losses on derivatives-hedging activities:		
Interest rate contracts	$ 157	Interest expense
Foreign currency contracts	(25)	Other, net
Total	132	
Tax	(34)	Income tax expense (benefit)
Total, net of tax	$ 98	
Unrecognized pension costs:		
Actuarial losses	$ 6	Other, net
Total	6	
Tax	(2)	Income tax expense (benefit)
Total, net of tax	$ 4	
2019		
Deferred (gains) and losses on derivatives-hedging activities:		
Commodity contracts	$ (4)	Net income from discontinued operations
Interest rate contracts	5	Interest expense
Foreign currency contracts	6	Other, net
Total	7	
Tax	(2)	Income tax expense (benefit)
Total, net of tax	$ 5	
Unrecognized pension costs:		
Actuarial losses	$ 7	Other, net
Total	7	
Tax	(2)	Income tax expense (benefit)
Total, net of tax	$ 5	

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, 2021 (in millions):

	AOCI After-Tax	Amounts Expected to be Reclassified to Earnings During the Next 12 Months After-Tax	Maximum Term
Interest rate	$ (38)	$ (4)	276 months
Foreign currency	(4)	(3)	54 months
Total	$ (42)	$ (7)	

The amounts that will be reclassified from AOCI to earnings will generally be offset by the recognition of the hedged transactions (e.g., interest payments) in earnings, thereby achieving the realization of prices contemplated by the underlying risk management strategies and will vary from the expected amounts presented above as a result of changes in interest rates and foreign currency exchange rates.

In July 2020, Eastern Energy Gas recorded a loss of $141 million ($105 million after-tax) in interest expense in the Consolidated Statement of Operations, for cash flow hedges of debt-related items that are probable of not occurring as a result of the GT&S Transaction. The derivatives related to these hedges were settled in October 2020 for a cash payment of $165 million.

(17) Variable Interest Entities

The primary beneficiary of a variable interest entity ("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 part of the Dominion Energy Gas Restructuring, DEI contributed to Eastern Energy Gas a 75% controlling limited partner interest in Cove Point. In December 2019, DEI sold its retained 25% noncontrolling limited partner interest in Cove Point. As discussed in Note 3, as part of the GT&S Transaction, Eastern Energy Gas finalized a restructuring which included the disposition of a 50% noncontrolling interest in Cove Point to DEI, which resulted in Eastern Energy Gas owning 100% of the general partner interest and 25% of the limited partnership interest in 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 $12 million, $12 million and $16 million for the years ended December 31, 2021, 2020 and 2019, respectively. Eastern Energy Gas' Consolidated Balance Sheets included amounts due to Carolina Gas Services of $7 million and $22 million as of December 31, 2021 and 2020 respectively. Eastern Energy Gas determined that neither it nor any of its consolidated entities is the primary beneficiary of Carolina Gas Services as neither it nor any of its consolidated entities has both 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 them. Carolina Gas Services provides marketing and operational services. Neither Eastern Energy Gas nor any of its consolidated entities has any obligation to absorb more than its allocated share of Carolina Gas Services costs.

Prior to the GT&S Transaction, Eastern Energy Gas purchased shared services from Dominion Energy Questar Pipeline Services, Inc. ("DEQPS"), an affiliated VIE, of $23 million and $33 million for the years ended December 31, 2020 and 2019, respectively. Eastern Energy Gas determined that neither it nor any of its consolidated entities was the primary beneficiary of DEQPS, as neither it nor any of its consolidated entities has both the power to direct the activities that most significantly impact their economic performance as well as the obligation to absorb losses and benefits which could be significant to them. DEQPS 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 DEQPS costs.

Prior to the GT&S Transaction, Eastern Energy Gas purchased shared services from Dominion Energy Services, Inc. ("DES"), an affiliated VIE, of $90 million and $119 million for the years ended December 31, 2020 and 2019, respectively. Eastern Energy Gas determined that neither it nor any of its consolidated entities was the primary beneficiary of DES as neither it nor any of its consolidated entities had both the power to direct the activities that most significantly impact their economic performance as well as the obligation to absorb losses and benefits which could be significant to them. DES provided accounting, legal, finance and certain administrative and technical services. Neither Eastern Energy Gas nor any of its consolidated entities had any obligation to absorb more than its allocated share of DES costs.

(18) Noncontrolling Interests

Included in noncontrolling interests in the Consolidated Financial Statements are DEI's 50% interest in Cove Point (effective November 2020), Brookfield's 25% interest in Cove Point (effective December 2019) and the public's ownership interest in Northeast Midstream (through January 2019).

Noncontrolling Interest in Northeast Midstream

Northeast Midstream was a publicly traded master limited partnership that included common units, subordinated units, Series A Preferred Units and incentive distribution rights as its participating securities. In accordance with the partnership agreement, when the subordination period ended, all subordinated units converted into common units on a one-for-one basis and participated pro rata with the other common units in distributions.

In January 2019, DEI and Northeast Midstream closed on an agreement and plan of merger pursuant to which DEI acquired each outstanding common unit representing limited partner interests in Northeast Midstream not already owned by DEI through the issuance of 22.5 million shares of common stock valued at $1.6 billion. Under the terms of the agreement and plan of merger, each publicly held outstanding common unit representing limited partner interests in Northeast Midstream was converted into the right to receive 0.2492 shares of DEI common stock. Immediately prior to the closing, each Series A Preferred Unit representing limited partner interests in Northeast Midstream was converted into common units representing limited partner interests in Northeast Midstream in accordance with the terms of Northeast Midstream's partnership agreement. The merger was accounted for by DEI following the guidance for a change in a parent company's ownership interest in a consolidated subsidiary. Because DEI controlled Northeast Midstream both before and after the merger, the changes in DEI's ownership interest in Northeast Midstream were accounted for as an equity transaction and no gain or loss was recognized. In connection with the merger, DEI recognized $40 million of income taxes in equity primarily attributable to establishing additional regulatory liabilities related to excess deferred income taxes and changes in state income taxes.

Subsequent to this activity, as a result of the Dominion Energy Gas Restructuring, Eastern Energy Gas is considered to have acquired all of the outstanding partnership interests of Northeast Midstream and Northeast Midstream became a wholly-owned subsidiary of Eastern Energy Gas.

(19) Supplemental Cash Flow Disclosures

Cash and Cash Equivalents and Restricted Cash and Cash Equivalents

Cash equivalents consist of funds invested in money market mutual funds, United States 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 presented in 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, 2021	December 31, 2020
Cash and cash equivalents	$ 22	$ 35
Restricted cash and cash equivalents	17	13
Total cash and cash equivalents and restricted cash and cash equivalents	$ 39	$ 48

The summary of supplemental cash flow disclosures as of and for the years ended December 31 is as follows (in millions):

	2021	2020	2019
Supplemental disclosure of cash flow information:			
Interest paid, net of amounts capitalized	$ 144	$ 317	$ 291
Income taxes (received) paid, net	$ (60)	$ 31	$ 65
Supplemental disclosure of non-cash investing and financing transactions:			
Accruals related to property, plant and equipment additions	$ 42	$ 30	$ 25
Equity distributions	$ (137)	$ —	$ —
Equity contributions	$ 73	$ —	$ —
Distribution of Questar Pipeline Group	$ —	$ (699)	$ —
Distribution of 50% interest in Cove Point	$ —	$ (2,765)	$ —
Acquisition of Eastern Energy Gas by BHE	$ —	$ 343	$ —

(20) Related Party Transactions

Transactions Prior to the GT&S Transaction

Prior to the GT&S Transaction, Eastern Energy Gas engaged in related party transactions primarily with other DEI subsidiaries (affiliates). Eastern Energy Gas' receivable and payable balances with affiliates were settled based on contractual terms or on a monthly basis, depending on the nature of the underlying transactions. Through October 31, 2020, Eastern Energy Gas was included in DEI's consolidated federal income tax return and, where applicable, combined state income tax returns. All affiliate payables or receivables were settled with DEI prior to the closing date of the GT&S Transaction.

Eastern Energy Gas transacted with affiliates for certain quantities of natural gas and other commodities at market prices in the ordinary course of business. Additionally, Eastern Energy Gas provided transportation and storage services to affiliates. Eastern Energy Gas also entered into certain other contracts with affiliates, and related parties, including construction services, which were presented separately from contracts involving commodities or services. See Note 3 for information regarding the Dominion Energy Gas Restructuring, an affiliated transaction. Eastern Energy Gas participated in certain DEI benefit plans as described in Note 10.

DES, Carolina Gas Services, DEQPS and other affiliates provided accounting, legal, finance and certain administrative and technical services to Eastern Energy Gas. Eastern Energy Gas provided certain services to related parties, including technical services.

The financial statements for the years ended December 31, 2020 and 2019 include costs for certain general, administrative and corporate expenses assigned by DES, Carolina Gas Services and DEQPS to Eastern Energy Gas on the basis of direct and allocated methods in accordance with Eastern Energy Gas' services agreements with DES, Carolina Gas Services and DEQPS. Where costs incurred cannot be determined by specific identification, the costs were allocated based on the proportional level of effort devoted by DES, Carolina Gas Services and DEQPS resources that is attributable to the entity, determined by reference to number of employees, salaries and wages and other similar measures for the relevant DES service. Management believes the assumptions and methodologies underlying the allocation of general corporate overhead expenses are reasonable.

Subsequent to the GT&S Transaction, and with the exception of Cove Point, Eastern Energy Gas' transactions with other DEI subsidiaries are no longer related party transactions.

Presented below are Eastern Energy Gas' significant transactions with DES, Carolina Gas Services, DEQPS and other affiliated and related parties for the years ended December 31 (in millions):

	2020	2019
Sales of natural gas and transportation and storage services	$ 207	$ 249
Purchases of natural gas and transportation and storage services	10	12
Services provided by related parties(1)	129	226
Services provided to related parties(2)	83	164

(1) Includes capitalized expenditures of $14 million and $19 million for the years ended December 31, 2020 and 2019, respectively.

(2) Includes amounts attributable to Atlantic Coast Pipeline, a related party VIE prior to the GT&S Transaction. See below for more information.

EGTS provided services to Atlantic Coast Pipeline, which totaled $46 million and $103 million for the years ended December 31, 2020 and 2019, respectively, included in operating revenue in the Consolidated Statements of Operations.

Interest income related to the affiliated notes receivable under the DEI money pool was $3 million for the year ended December 31, 2020.

Interest income on affiliated notes receivable from East Ohio and EGP borrowings under intercompany revolving credit agreements with Eastern Energy Gas was $14 million for the year ended December 31, 2019.

Interest income related to DEI's loan and promissory note associated with Cove Point's term loan was $82 million for the year ended December 31, 2019. In September 2019, DEI repaid the promissory note to Cove Point and the proceeds were used by Cove Point to repay its $3.0 billion term loan.

Eastern Energy Gas' affiliated notes receivable from DEI totaled $1.8 billion as of December 31, 2019. In August 2020, DEI repaid the remaining principal balance outstanding. Interest income on the promissory notes was $32 million and $5 million for the years ended December 31, 2020 and 2019, respectively.

As of December 31, 2019, Eastern Energy Gas' affiliated notes receivable from East Ohio totaled $1.7 billion. In June 2020, East Ohio repaid the remaining principal balance outstanding. Interest income on these promissory notes was $33 million and $72 million for the years ended December 31, 2020 and 2019, respectively.

Interest charges related to Eastern Energy Gas' total borrowings under an intercompany revolving credit agreement with DEI were $3 million for each of the years ended December 31, 2020 and 2019.

Interest charges related to DCP's total borrowings from DEI totaled $94 million for the year ended December 31, 2019.

Interest charges related to DCP's total borrowings from DES were $3 million for each of the years ended December 31, 2020 and 2019.

Interest charges related to Northeast Midstream's promissory note with DEI were $10 million for the year ended December 31, 2019.

For the years ended December 31, 2020 and 2019, Eastern Energy Gas, including entities acquired in the Dominion Energy Gas Restructuring, distributed $4.3 billion and $603 million to DEI, respectively.

Transactions Subsequent to the GT&S Transaction

Eastern Energy Gas is party to a tax-sharing agreement and is part of the Berkshire Hathaway consolidated United States federal income tax return. For current federal and state income taxes, Eastern Energy Gas had a receivable from BHE of $8 million and $20 million as of December 31, 2021 and 2020, respectively. Eastern Energy Gas received net cash receipts for federal and state income taxes from BHE totaling $47 million and $76 million for the years ended December 31, 2021 and 2020, respectively.

Other assets included amounts due from an affiliate of $3 million and $7 million as of December 31, 2021 and 2020, respectively.

As of December 31, 2021, Eastern Energy Gas had $5 million of natural gas imbalances payable to affiliates, presented in other current liabilities on the Consolidated Balance Sheet.

Presented below are Eastern Energy Gas' significant transactions with affiliated and related parties for the years ended December 31 (in millions):

	2021	2020
Sales of natural gas and transportation and storage services	$ 32	$ 4
Purchases of natural gas and transportation and storage services	5	—
Services provided by related parties	51	4
Services provided to related parties	32	7

Eastern Energy Gas has a $400 million intercompany revolving credit agreement from its parent, BHE GT&S, expiring in November 2022. 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 London Interbank Offered Rate ("LIBOR") plus a fixed spread. As of December 31, 2020, $9 million was outstanding under the credit agreement with a weighted average interest rate of 0.55%. There were no amounts outstanding under the credit agreement as of December 31, 2021.

BHE GT&S has an intercompany revolving credit agreement from Eastern Energy Gas expiring in December 2022. In March 2021, BHE GT&S increased its credit facility limit from $200 million to $400 million. The credit agreement has a variable interest rate based on LIBOR plus a fixed spread. As of December 31, 2021 and 2020, $8 million and $124 million, respectively, was outstanding under the credit agreement.

Eastern Energy Gas participates in certain MidAmerican Energy benefit plans as described in Note 10. As of December 31, 2021 and 2020, 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 $95 million and $115 million, respectively.

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 and Eastern Energy Gas Holdings, LLC 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 United States 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, 2021 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 and Eastern Energy Gas Holdings, LLC, 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, 2021, 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, 2021.

Berkshire Hathaway Energy Company February 25, 2022	PacifiCorp February 25, 2022	MidAmerican Funding, LLC February 25, 2022
MidAmerican Energy Company February 25, 2022	Nevada Power Company February 25, 2022	Sierra Pacific Power Company February 25, 2022
Eastern Energy Gas Holdings, LLC February 25, 2022		

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 AND EASTERN ENERGY GAS

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, 2022, with respect to the current directors and executive officers of PacifiCorp:

WILLIAM J. FEHRMAN, 61, Chair of the Board of Directors and Chief Executive Officer since January 2018. Mr. Fehrman has also been President, Chief Executive Officer and Director of BHE since January 2018. Mr. Fehrman was Chief Executive Officer of MidAmerican Energy Company from 2008 to January 2018 and President and Director from 2007 to January 2018. Mr. Fehrman joined BHE in 2006 and has extensive executive management experience in the energy industry with strong regulatory and operational skills.

STEFAN A. BIRD, 55, Director since 2015. President and Chief Executive Officer of Pacific Power since 2015. Mr. Bird was Senior Vice President, Commercial and Trading, of PacifiCorp from 2007 to 2014. Mr. Bird joined BHE in 1998 and has significant operational, public policy and leadership experience in the energy industry, including expertise in energy supply management, resource acquisition and federal and state regulatory matters.

GARY W. HOOGEVEEN, 53, 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, 49, 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, 53, 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, 52, 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, 2021, 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 AND EASTERN ENERGY GAS

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

Mr. William J. Fehrman, PacifiCorp's Chair of the Board of Directors and Chief Executive Officer, or Chair and CEO, received no direct compensation from PacifiCorp. PacifiCorp reimbursed its indirect parent company, BHE, for the cost of Mr. Fehrman'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.

PacifiCorp believes that the compensation paid to each of its Chief Financial Officer, or CFO, and its other most highly compensated executive officers, to whom PacifiCorp refers collectively as its Named Executive Officers, or NEOs, should be closely aligned with its 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 its NEOs, such as approving 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

PacifiCorp determines base salaries for all of its NEOs, other than the Chair and CEO, by reviewing its 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 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 2021, base salaries for all NEOs, other than the Chair and CEO, increased on average by 1.39% effective December 26, 2020, reflecting merit increases.

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.

Annual Incentive Plan

Under PacifiCorp's Annual Incentive Plan, or AIP, all NEOs, other than the Chair and CEO, 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 using financial and non-financial 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 2021. Approved awards are paid prior to year-end.

Performance Awards

In addition to the annual awards under the AIP, PacifiCorp may grant 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. In 2021, a cash performance award was granted to Ms. Kobliha in recognition of her outstanding efforts.

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, or 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, participate in the LTIP. The LTIP provides for annual discretionary awards based upon significant accomplishments by the individual participants and the achievement of the financial and non-financial 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 Chair and PacifiCorp's Presidents approve eligibility to participate in the LTIP 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 Chair shall make determinations regarding their participation and the value of their incentive award. These cash-based 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.

Deferred Compensation Plan

PacifiCorp's Executive Voluntary Deferred Compensation Plan, or DCP, provides a means for all NEOs, other than the Chair and CEO, to make voluntary deferrals of up to 50% of base salary and 100% of 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 plan allows participants to choose from three forms of distribution. The plan permits PacifiCorp to make discretionary contributions on behalf of participants.

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 an employment agreement; therefore, payments upon termination are determined by the applicable plan documents and our general employment policies and practices as discussed below.

Compensation Committee Report

Mr. Fehrman, PacifiCorp's current Chair and CEO and sole member of PacifiCorp's compensation committee, has reviewed the Compensation Discussion and Analysis and, based on this review, has recommended to the Board of Directors that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K.

William J. Fehrman

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)
William J. Fehrman(5)	2021	$ —	$ —	$ —	$ —	$ —
Chair of the Board of Directors	2020	—	—	—	—	—
and Chief Executive Officer	2019	—	—	—	—	—
Stefan A. Bird	2021	473,011	1,142,660	—	33,010	1,648,681
President and Chief Executive	2020	375,000	1,327,839	17,723	33,479	1,754,041
Officer, Pacific Power	2019	365,000	1,286,958	10,152	31,845	1,693,955
Gary W. Hoogeveen	2021	473,011	1,066,924	—	33,010	1,572,945
President and Chief Executive	2020	361,080	1,109,713	—	32,690	1,503,483
Officer, Rocky Mountain Power	2019	350,000	964,837	—	32,731	1,347,568
Nikki L. Kobliha	2021	262,260	396,880	—	32,651	691,791
Vice President, Chief Financial	2020	262,260	330,510	37,438	32,286	662,494
Officer and Treasurer	2019	239,571	243,289	33,825	31,391	548,076

(1) Consists of annual cash incentive awards earned pursuant to the AIP for PacifiCorp's NEOs, performance awards, and the vesting of LTIP awards and associated vested earnings. The breakout for 2021 is as follows:

			LTIP		
	AIP	Performance Award	Vested Awards	Vested Earnings	Total
Stefan A. Bird	$ 400,000	$ —	$ 685,250	$ 57,410	$ 742,660
Gary W. Hoogeveen	400,000	—	467,000	199,924	666,924
Nikki L. Kobliha	96,512	40,000	157,125	103,243	260,368

The ultimate payouts of LTIP awards are undeterminable as the amounts to be paid out may increase or decrease depending on investment performance. BHE's Chair and PacifiCorp's Presidents establish the award categories for determining LTIP awards based on net income target goals or other criteria. In 2021, the gross award was subjectively determined at the discretion of the BHE Chair and PacifiCorp's Presidents based on the overall achievement of PacifiCorp's financial and non-financial objectives including customer service, employee commitment and safety, environmental respect, regulatory integrity, operational excellence and financial strength.

(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. For Mr. Bird and Ms. Kobliha, such change was negative ($(10,705) and $(14,812), respectively. 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) Amounts consist of PacifiCorp K Plus Employee Savings Plan, or 401(k) Plan, contributions PacifiCorp paid on behalf of the NEOs.

(4) Any amounts voluntarily deferred by the NEO, if applicable, are included in the appropriate column in the Summary Compensation Table.

(5) In 2021, PacifiCorp reimbursed BHE $239,746 for the cost of Mr. Fehrman's time spent on matters supporting PacifiCorp pursuant to the intercompany administrative services agreement.

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, 2021:

Name	Plan name	Number of years of credited service	Present value of accumulated benefits (1)
William J. Fehrman	n/a	n/a	n/a
Stefan A. Bird	Retirement	10 years	$ 223,944
Gary W. Hoogeveen	n/a	n/a	n/a
Nikki L. Kobliha	Retirement	12 years	168,600

(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, 2021, 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: 80% lump sum payment; 20% joint and 100% survivor annuity if participant is married and 20% single life annuity if participant is single. For 2023 and beyond, the lump sum payment assumption decreases from 80% to 60%, and the annuity assumption increases from 20% to 40%. The present value assumptions used in calculating the present value of accumulated benefits for the Retirement Plan were as follows: a discount rate of 2.90%; an expected retirement age of 65; cash balance interest crediting assumption of 0.88% for 2022 and 2023, and 1.90% thereafter; postretirement mortality using the Pri-2012 gender specific tables; generational mortality improvements from 2012 forward based on MP-2021; a lump sum interest rate of 2.90%; and lump sum mortality using the unisex tables set forth in IRC 417(e)(3) for the upcoming fiscal year with mortality improvements determined using MP-2020.

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 restated 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 Mr. Bird) with pay credits equivalent to those received in the Retirement Plan allocated into the 401(k) Plan. 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, 2021:

Name	Executive contributions in 2021(1)(2)	Registrant contributions in 2021	Aggregate earnings/losses in 2021	Aggregate withdrawals/ distributions	Aggregate balance as of 12/31/2021(3)
William J. Fehrman	$ —	$ —	$ —	$ —	$ —
Stefan A. Bird	—	—	—	—	—
Gary W. Hoogeveen	321,836	—	388,591	—	3,866,753
Nikki L. Kobliha	275,387	—	21,358	—	536,872

(1) The executive contribution amount shown for Mr. Hoogeveen represents a deferral of $321,836 of his 2018 LTIP award which was deferred in 2021. $177,747 of the deferred 2018 LTIP award is included in the 2021 total compensation reported for him in the Summary Compensation Table and is not additional compensation. The remaining LTIP award was earned prior to 2021.

(2) The executive contribution amount shown for Ms. Kobliha represents a deferral of $47,241 of her 2021 compensation and a deferral of $228,146 of her 2018 LTIP award which was deferred in 2021. $85,123 of the deferred 2018 LTIP award is included in the 2021 total compensation reported for her in the Summary Compensation Table and is not additional compensation. The remaining LTIP award was earned prior to 2021.

(3) The aggregate balance as of December 31, 2021, shown for Mr. Hoogeveen and Ms. Kobliha includes $389,955 and $51,580, 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 an employment agreement; therefore, payments upon termination are determined by the applicable plan documents and our 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, other than Mr. Fehrman. 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, 2021 and are payable as lump sums unless otherwise noted.

Termination Scenario	Incentive [1]	Pension [2]
Stefan A. Bird:		
Retirement, Voluntary and Involuntary With or Without Cause	$ —	$ 25,849
Death and Disability	1,016,704	25,849
Gary W. Hoogeveen:		
Retirement, Voluntary and Involuntary With or Without Cause	—	n/a
Death and Disability	858,232	n/a
Nikki L. Kobliha:		
Retirement, Voluntary and Involuntary With or Without Cause	—	—
Death and Disability	274,334	—

(1) Amounts represent the unvested portion of each NEO's LTIP account, which becomes 100% vested under certain circumstances.

(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 CEO receives no direct compensation from PacifiCorp, and no amounts are reported for the CEO in the Summary Compensation Table. Accordingly, PacifiCorp has determined that the CEO pay ratio is not calculable.

Director Compensation

PacifiCorp's directors do not receive additional compensation for service as directors of PacifiCorp. Compensation information for Messrs. Fehrman, Bird, Hoogeveen, and Ms. Kobliha for their services as executive officers of PacifiCorp is described above.

Compensation Committee Interlocks and Insider Participation

Mr. Fehrman is PacifiCorp's Chair and CEO and also the President and Chief Executive Officer of BHE. 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 (other than BHE) 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 AND EASTERN ENERGY GAS

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, 2022, owns 91.1% of BHE's common stock. The balance of BHE's common stock is beneficially owned by family members and related or affiliated entities of the late Mr. Walter Scott, Jr., a former member of BHE's Board of Directors, and Gregory E. Abel, BHE's Chair.

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, 2022:

	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)
William J. Fehrman	—	—	—	—	—	—
Stefan A. Bird	—	—	—	—	—	—
Calvin D. Haack	—	—	—	—	—	—
Natalie L. Hocken	—	—	—	—	—	—
Nikki L. Kobliha	—	—	—	—	—	—
Gary W. Hoogeveen	—	—	—	—	512	*
All executive officers and directors as a group (6 persons)	—	—	—	—	512	*

* 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 AND EASTERN ENERGY GAS

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
2021							
Audit fees(2)	$ 11.3	$ 1.7	$ 1.3	$ 1.2	$ 0.9	$ 0.9	$ 1.2
Audit-related fees(3)	0.8	0.1	0.1	0.1	—	—	0.2
Tax fees(4)	0.1	—	—	—	—	—	—
Total	$ 12.2	$ 1.8	$ 1.4	$ 1.3	$ 0.9	$ 0.9	$ 1.4
2020							
Audit fees(2)	$ 10.6	$ 1.5	$ 1.1	$ 1.0	$ 0.9	$ 0.9	$ 0.8
Audit-related fees(3)	0.7	0.1	0.2	0.2	—	—	0.4
Tax fees(4)	0.1	—	—	—	—	—	—
Total	$ 11.4	$ 1.6	$ 1.3	$ 1.2	$ 0.9	$ 0.9	$ 1.2

(1) The reported fees for Berkshire Hathaway Energy include those fees reported for PacifiCorp, MidAmerican Funding, Nevada Power, Sierra Pacific and Eastern Energy Gas (since November 1, 2020 acquisition date totaling $0.9 million) while the reported fees for MidAmerican Funding include those fees reported for MidAmerican Energy.

(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

The financial statements of all Registrants are included in their respective Item 8 of this Form 10-K.	100

(2) Financial Statement Schedules

BHE Parent Company Only Condensed Financial Statements (Schedule I)	466
MidAmerican Funding, LLC Parent Company Only Condensed Financial Statements (Schedule I)	471

Schedules not listed above have been omitted because they are either not applicable, not required or the information required to be set forth therein is included on the Consolidated Financial Statements or notes thereto.

(3) Management contracts or compensatory plans are identified by an asterisk in the Exhibit Index filed as part of this Annual Report.	474

(b) Exhibits

The exhibits listed on the accompanying Exhibit Index are filed as part of this Annual Report.	474

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, 2021	2020
ASSETS		
Current assets:		
Cash and cash equivalents	$ 18	$ 623
Accounts receivable - affiliate	117	96
Notes receivable - affiliate	189	177
Income tax receivable	23	19
Other current assets	13	1,301
Total current assets	360	2,216
Investments in subsidiaries	58,190	48,654
Other investments	237	6,103
Goodwill	1,221	1,221
Other assets	1,101	488
Total assets	$ 61,109	$ 58,682
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable and other current liabilities	$ 397	$ 341
Notes payable - affiliate	353	200
Current portion of BHE senior debt	—	450
Total current liabilities	750	991
BHE senior debt	13,003	12,997
BHE junior subordinated debentures	100	100
Notes payable - affiliate	2	116
Other long-term liabilities	560	1,468
Total liabilities	14,415	15,672
Equity:		
BHE shareholders' equity:		
Preferred stock - 100 shares authorized, $0.01 par value, 2 and 4 shares issued and outstanding	1,650	3,750
Common stock - 115 shares authorized, no par value, 76 shares issued and outstanding	—	—
Additional paid-in capital	6,374	6,377
Long-term income tax receivable	(744)	(658)
Retained earnings	40,754	35,093
Accumulated other comprehensive loss, net	(1,340)	(1,552)
Total BHE shareholders' equity	46,694	43,010
Noncontrolling interest	—	—
Total equity	46,694	43,010
Total liabilities and equity	$ 61,109	$ 58,682

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,		
	2021	**2020**	**2019**
Operating expenses:			
General and administration	$ 83	$ 57	$ 49
Depreciation and amortization	6	4	5
Total operating expenses	89	61	54
Operating loss	(89)	(61)	(54)
Other income (expense):			
Interest expense	(580)	(527)	(452)
Other, net	1,846	4,789	(271)
Total other income (expense)	1,266	4,262	(723)
Income (loss) before income tax expense (benefit) and equity income	1,177	4,201	(777)
Income tax expense (benefit)	194	1,089	(312)
Equity income	4,807	3,832	3,419
Net income	5,790	6,944	2,954
Net income attributable to noncontrolling interest	—	1	3
Net income attributable to BHE shareholders	5,790	6,943	2,951
Preferred dividends	121	26	—
Earnings on common shares	$ 5,669	$ 6,917	$ 2,951

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,		
	2021	**2020**	**2019**
Net income	$ 5,790	$ 6,944	$ 2,954
Other comprehensive income, net of tax	212	154	239
Comprehensive income	6,002	7,098	3,193
Comprehensive income attributable to noncontrolling interests	—	1	3
Comprehensive income attributable to BHE shareholders	$ 6,002	$ 7,097	$ 3,190

The accompanying notes are an integral part of this financial statement schedule.

BERKSHIRE HATHAWAY ENERGY COMPANY
PARENT COMPANY ONLY
CONDENSED STATEMENTS OF CASH FLOWS
(In millions)

	Years Ended December 31,		
	2021	**2020**	**2019**
Cash flows from operating activities	$ 1,819	$ 1,639	$ 1,780
Cash flows from investing activities:			
Investments in subsidiaries	(1,206)	(6,422)	(1,972)
Purchases of marketable securities	(29)	(55)	(42)
Proceeds from sales of marketable securities	28	22	41
Purchases of other investments	—	(1,290)	—
Proceeds from other investments	1,290	—	1
Notes receivable from affiliate, net	200	(121)	(112)
Other, net	(20)	(20)	(5)
Net cash flows from investing activities	263	(7,886)	(2,089)
Cash flows from financing activities:			
Proceeds from issuance of preferred stock	—	3,750	—
Preferred stock redemptions	(2,100)	—	—
Preferred dividends	(132)	(7)	—
Common stock purchases	—	(126)	(293)
Proceeds from BHE senior debt	—	5,212	—
Repayments of BHE senior debt	(450)	(350)	—
Net (repayments of) proceeds from short-term debt	—	(1,590)	607
Other, net	(5)	(32)	(1)
Net cash flows from financing activities	(2,687)	6,857	313
Net change in cash and cash equivalents	(605)	610	4
Cash and cash equivalents at beginning of year	623	13	9
Cash and cash equivalents at end of year	$ 18	$ 623	$ 13

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.

Other investments - BHE's investment in BYD Company Limited ("BYD") common stock is accounted for as a marketable security with changes in fair value recognized in net income. As of December 31, 2021 and 2020, the fair value of BHE's investment in BYD common stock was $— million and $5,897 million, respectively.

Dividends and distributions from subsidiaries - Cash dividends paid to BHE by its subsidiaries for the years ended December 31, 2021, 2020 and 2019 were $2.4 billion, $2.0 billion and $2.0 billion, respectively. In January and February 2022, BHE received cash dividends from its subsidiaries totaling $102 million.

Guarantees and commitments - BHE has issued guarantees and letters of credit in respect of subsidiaries, equity method investments and other related parties aggregating $1.4 billion and commitments, subject to satisfaction of certain specified conditions, to provide equity contributions in support of renewable tax equity investments totaling $356 million.

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).

Schedule I

MIDAMERICAN FUNDING, LLC
PARENT COMPANY ONLY
CONDENSED BALANCE SHEETS
(Amounts in millions)

	As of December 31,	
	2021	**2020**
ASSETS		
Current assets:		
Receivables from affiliates	$ 1	$ 1
Investments in and advances to subsidiaries	10,070	9,176
Total assets	$ 10,071	$ 9,177
LIABILITIES AND MEMBER'S EQUITY		
Current liabilities:		
Interest accrued and other current liabilities	$ 5	$ 5
Payable to affiliate	25	13
Long-term debt	240	240
Total liabilities	270	258
Member's equity:		
Paid-in capital	1,679	1,679
Retained earnings	8,122	7,240
Total member's equity	9,801	8,919
Total liabilities and member's equity	$ 10,071	$ 9,177

The accompanying notes are an integral part of this financial statement schedule.

Schedule I

MIDAMERICAN FUNDING, LLC
PARENT COMPANY ONLY
CONDENSED STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2021	**2020**	**2019**
Other income and (expense):			
Interest expense	$ (16)	$ (16)	$ (16)
Loss before income taxes	(16)	(16)	(16)
Income tax benefit	(5)	(5)	(5)
Equity in undistributed earnings of subsidiaries	894	829	792
Net income	$ 883	$ 818	$ 781

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,		
	2021	**2020**	**2019**
Net cash flows from operating activities	$ (12)	$ (12)	$ (12)
Net cash flows from investing activities	—	—	—
Net cash flows from financing activities:			
Net change in amounts payable to subsidiary	12	12	12
Net cash flows from financing activities	12	12	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 Equity for the three years ended December 31, 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, 2021, 2020 and 2019.

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 primarily interest costs on, and repayments of, MidAmerican Funding's long-term debt and income taxes. MHC paid $12 million in 2021, 2020 and 2019 on behalf of MidAmerican Funding. In 2019, MHC transferred to MidAmerican Funding $440 million of its receivable from MidAmerican Funding in the form of a dividend.

Distribution to Parent - In 2019, MidAmerican Funding recorded a noncash dividend of $8 million for the transfer to BHE of corporate aircraft owned by MHC.

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	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).
4.16	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).
4.17	Trust Deed, dated December 15, 1997 among CE Electric UK Funding Company, AMBAC Insurance UK Limited and The Law Debenture Trust Corporation, p.l.c., Trustee (incorporated by reference to Exhibit 99.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated March 30, 2004).
4.18	Insurance and Indemnity Agreement, dated December 15, 1997 by and between CE Electric UK Funding Company and AMBAC Insurance UK Limited (incorporated by reference to Exhibit 99.2 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated March 30, 2004).
4.19	Supplemental Agreement to Insurance and Indemnity Agreement, dated September 19, 2001, by and between CE Electric UK Funding Company and AMBAC Insurance UK Limited (incorporated by reference to Exhibit 99.3 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated March 30, 2004).
4.20	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).
4.21	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).
4.22	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).
4.23	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).
4.24	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).

Exhibit No.	Description
4.25	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).
4.26	Supplemental Trust Deed, dated May 5, 2005 among CE Electric UK Funding Company, Ambac Assurance UK Limited and The Law Debenture Trust Corporation plc (incorporated by reference to Exhibit 99.5 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2005).
4.27	Second Supplemental Agreement to Insurance and Indemnity Agreement, dated May 5, 2005 by and between CE Electric UK Funding Company and Ambac Assurance UK Limited (incorporated by reference to Exhibit 99.6 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2005).
4.28	£151,000,000 Finance Contract, dated July 2, 2010, by and between Yorkshire Electricity Distribution 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, 2010).
4.29	Guarantee and Indemnity Agreement, dated July 2, 2010, by and between CE Electric UK Funding 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, 2010).
4.30	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).
4.31	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).
4.32	£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).
4.33	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).
4.34	£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).
4.35	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).
4.36	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).
4.37	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).
4.38	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).
4.39	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).

Exhibit No.	Description
4.40	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).
4.41	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).
4.42	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).
4.43	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).
4.44	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).
4.45	Master Trust Indenture, dated November 21, 2005, by and between AltaLink Investments, L.P., AltaLink Investment Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.94 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.46	Third Supplemental Indenture, dated December 15, 2010, by and between AltaLink Investments, L.P., AltaLink Investment Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.96 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.47	Series 15-1 Supplemental Indenture, dated March 6, 2015, by and between AltaLink Investments, L.P., AltaLink Investment Management Ltd. and BNY Trust Company of Canada, relating to C$200,000,000 in principal amount of the 2.244% Series 15-1 Senior Bonds due 2022 (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, 2015).
4.48	2016 Supplemental Indenture, dated December 9, 2016, by and between AltaLink Investments, L.P., AltaLink Investment Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.53 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2016).
4.49	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).
4.50	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).
4.51	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).
4.52	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).
4.53	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).

Exhibit No.	Description
4.54	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).
4.55	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).
4.56	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).
4.57	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).
4.58	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).
4.59	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).
4.60	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).
4.61	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).
4.62	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).
4.63	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).
4.64	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	$3,500,000,000 Second Amended and Restated Credit Agreement, dated as of June 30, 2021, among Berkshire Hathaway Energy Company, as Borrower, the Banks, Financial Institutions and Other Institutional Lenders, as Initial Lenders, MUFG Union Bank, N.A, 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, 2021).
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.

Exhibit No.	Description
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.
10.5	Fourth Amended and Restated Credit Agreement, dated as of January 24, 2020, among AltaLink, L.P., as borrower, AltaLink Management Ltd., as general partner, The Bank of Nova Scotia, as administrative agent, and Lenders (incorporated by reference to Exhibit 10.5 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2019).
10.6	Second Amending Agreement to Fourth Amended and Restated Credit Agreement, dated as of December 15, 2021, among AltaLink, L.P., as borrower, AltaLink Management Ltd., as general partner and The Bank of Nova Scotia, as administrative agent.
10.7	Fifth Amended and Restated Credit Agreement, dated as of January 24, 2020, among AltaLink, L.P., as borrower, AltaLink Management Ltd., as general partner, The Bank of Nova Scotia, 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, 2019).
10.8	Second Amending Agreement to Fifth Amended and Restated Credit Agreement, dated as of December 15, 2021, among AltaLink, L.P., as borrower, AltaLink Management Ltd., as general partner, The Bank of Nova Scotia, as administrative agent and Lenders.
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	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).
10.11	Berkshire Hathaway Energy Company Long-Term Incentive Partnership Plan as Amended and Restated 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 May 23, 2005 (incorporated by reference to Exhibit 3.2 to the PacifiCorp Annual Report on Form 10-K for the year ended March 31, 2005).
10.12*	Summary of Key Terms of Compensation Arrangements with PacifiCorp's Named Executive Officers and Directors.
10.13*	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).
10.14*	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
10.15*	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).
10.16*	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).
10.17*	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).
10.18*	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).
10.19*	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).
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

4.65 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 31 Supplemental Indentures, each incorporated by reference, as follows:

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

10.20 $1,200,000,000 Second Amended and Restated Credit Agreement dated as of June 30, 2021, 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 10.2 to the PacifiCorp Quarterly Report on Form 10-Q for the quarter ended June 30, 2021).

95 Mine Safety Disclosures Required by the Dodd-Frank Wall Street Reform and Consumer Protection Act.

Exhibit No.	Description
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	
4.66	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).
4.67	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).
4.68	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).
4.69	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).

Exhibit No.	Description
4.70	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).
4.71	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).
4.72	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).
4.73	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).
4.74	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).
4.75	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).
4.76	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).
4.77	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).
4.78	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).
4.79	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).
4.80	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).
4.81	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).
4.82	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).
4.83	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).
4.84	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).
4.85	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).
4.86	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).
4.87	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).

Exhibit No.	Description
4.88	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).
4.89	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).
4.90	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).
4.91	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).
4.92	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).
4.93	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).
4.94	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).
4.95	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).
4.96	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).
4.97	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).
4.98	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).
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).
10.21	$1,500,000,000 Second Amended and Restated Credit Agreement, dated as of June 30, 2021, 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 10.3 to the MidAmerican Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2021).

Exhibit No.	Description

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).
10.22	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).
10.23	$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.
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	First Supplemental Indenture, dated as of May 1, 2001 (incorporated by reference to Exhibit 4.1(b) to the Nevada Power Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2001).
4.107	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).
4.108	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).
4.109	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).
4.110	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).
4.111	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).
4.112	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).
4.113	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).
4.114	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).
4.115	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).
10.24	$400,000,000 Fourth Amended and Restated Credit Agreement, dated as of June 30, 2021, 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 10.4 to the Nevada Power Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2021).
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 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).
4.116	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).
4.117	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).

Exhibit No.	Description
4.118	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).
10.25	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).
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

4.119	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).
4.120	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).
4.121	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).
4.122	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).
4.123	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).
4.124	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).
10.26	$250,000,000 Fourth Amended and Restated Credit Agreement, dated as of June 30, 2021, 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 10.5 to the Sierra Pacific Power Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2021).

EASTERN ENERGY GAS

3.16	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).
3.17	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).
3.18	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).

Exhibit No.	Description
10.27	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).
10.28	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).
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

4.125	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).
4.126	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).
4.127	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).
4.128	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).
4.129	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).
4.130	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).
4.131	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).
4.132	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).
4.133	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).
4.134	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).
4.135	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 3.0% 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).

Exhibit No.	Description
4.136	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).
4.137	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).
4.138	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).
4.139	Indenture, dated as of June 30, 2021, by and between Eastern Gas Transmission and Storage, Inc. and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated by reference to Exhibit 4.6 to the Eastern Energy Gas Holdings, LLC Quarterly Report on Form 10-Q for the quarter ended June 30, 2021).
4.140	First Supplemental Indenture, dated as of June 30, 2021, by and between Eastern Gas Transmission and Storage, Inc. and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of June 30, 2021, and relating to the 3.900% Senior Notes due 2049 (incorporated by reference to Exhibit 4.7 to the Eastern Energy Gas Holdings, LLC Quarterly Report on Form 10-Q for the quarter ended June 30, 2021).
4.141	Second Supplemental Indenture, dated as of June 30, 2021, by and between Eastern Gas Transmission and Storage, Inc. and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of June 30, 2021, and relating to the 4.600% Senior Notes due 2044 (incorporated by reference to Exhibit 4.8 to the Eastern Energy Gas Holdings, LLC Quarterly Report on Form 10-Q for the quarter ended June 30, 2021).
4.142	Third Supplemental Indenture, dated as of June 30, 2021, by and between Eastern Gas Transmission and Storage, Inc. and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of June 30, 2021, and relating to the 4.800% Senior Notes due 2043 (incorporated by reference to Exhibit 4.9 to the Eastern Energy Gas Holdings, LLC Quarterly Report on Form 10-Q for the quarter ended June 30, 2021).
4.143	Fourth Supplemental Indenture, dated as of June 30, 2021, by and between Eastern Gas Transmission and Storage, Inc. and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of June 30, 2021, and relating to the 3.000% Senior Notes due 2029 (incorporated by reference to Exhibit 4.10 to the Eastern Energy Gas Holdings, LLC Quarterly Report on Form 10-Q for the quarter ended June 30, 2021).
4.144	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 Eastern Energy Gas Holdings, LLC Quarterly Report on Form 10-Q for the quarter ended June 30, 2021).
10.29	$400,000,000 Inter-Company Credit Agreement, dated as of November 1, 2020, by and between BHE GT&S, LLC and Eastern Energy Gas Holdings, LLC (incorporated by reference to Exhibit 10.3 to the Eastern Energy Gas Holdings, LLC Quarterly Report on Form 10-Q for the quarter ended September 30, 2020).

ALL REGISTRANTS

101	The following financial information from each respective Registrant's Annual Report on Form 10-K for the year ended December 31, 2021 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 25th day of February 2022.

BERKSHIRE HATHAWAY ENERGY COMPANY

/s/ William J. Fehrman*

William J. Fehrman
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/ William J. Fehrman* William J. Fehrman	Director, President and Chief Executive Officer (principal executive officer)	February 25, 2022
/s/ Calvin D. Haack* Calvin D. Haack	Senior Vice President and Chief Financial Officer (principal financial and accounting officer)	February 25, 2022
/s/ Gregory E. Abel* Gregory E. Abel	Chair of the Board of Directors	February 25, 2022
/s/ Warren E. Buffett* Warren E. Buffett	Director	February 25, 2022
/s/ Marc D. Hamburg* Marc D. Hamburg	Director	February 25, 2022
*By: /s/ Natalie L. Hocken Natalie L. Hocken	Attorney-in-Fact	February 25, 2022

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 25th day of February 2022.

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/ William J. Fehrman William J. Fehrman	Chair of the Board of Directors and Chief Executive Officer (principal executive officer)	February 25, 2022
/s/ Nikki L. Kobliha Nikki L. Kobliha	Director, Vice President, Chief Financial Officer and Treasurer (principal financial and accounting officer)	February 25, 2022
/s/ Stefan A. Bird Stefan A. Bird	Director	February 25, 2022
/s/ Calvin D. Haack Calvin D. Haack	Director	February 25, 2022
/s/ Natalie L. Hocken Natalie L. Hocken	Director	February 25, 2022
/s/ Gary W. Hoogeveen Gary W. Hoogeveen	Director	February 25, 2022

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 25th day of February 2022.

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 25, 2022
/s/ Thomas B. Specketer Thomas B. Specketer	Director, Vice President and Chief Financial Officer (principal financial and accounting officer)	February 25, 2022

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 25th day of February 2022.

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 25, 2022
/s/ Thomas B. Specketer Thomas B. Specketer	Vice President and Controller (principal financial and accounting officer)	February 25, 2022
/s/ Daniel S. Fick Daniel S. Fick	Manager	February 25, 2022
/s/ Calvin D. Haack Calvin D. Haack	Manager	February 25, 2022
/s/ Natalie L. Hocken Natalie L. Hocken	Manager	February 25, 2022

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 25th day of February 2022.

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 25, 2022
/s/ Michael E. Cole Michael E. Cole	Director, Vice President, Chief Financial Officer and Treasurer (principal financial and accounting officer)	February 25, 2022
/s/ Brandon M. Barkhuff Brandon M. Barkhuff	Director	February 25, 2022
/s/ Jennifer L. Oswald Jennifer L. Oswald	Director	February 25, 2022
/s/ Anthony F. Sanchez, III Anthony F. Sanchez, III	Director	February 25, 2022

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 25th day of February 2022.

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	Director, President and Chief Executive Officer	February 25, 2022
Douglas A. Cannon	(principal executive officer)	
/s/ Michael E. Cole	Director, Vice President, Chief Financial Officer and Treasurer	February 25, 2022
Michael E. Cole	(principal financial and accounting officer)	
/s/ Brandon M. Barkhuff	Director	February 25, 2022
Brandon M. Barkhuff		
/s/ Jennifer L. Oswald	Director	February 25, 2022
Jennifer L. Oswald		
/s/ Anthony F. Sanchez, III	Director	February 25, 2022
Anthony F. Sanchez, III		

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 25th day of February 2022.

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 25, 2022
/s/ Scott C. Miller Scott C. Miller	Vice President, Chief Financial Officer and Treasurer (principal financial officer)	February 25, 2022
/s/ Mark A. Hewett Mark A. Hewett	Manager	February 25, 2022
/s/ Calvin D. Haack Calvin D. Haack	Manager	February 25, 2022
/s/ Natalie L. Hocken Natalie L. Hocken	Manager	February 25, 2022

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.

EXHIBIT 21.1

BERKSHIRE HATHAWAY ENERGY COMPANY
SUBSIDIARIES AND JOINT VENTURES

Pursuant to Item 601(b)(21)(ii) of Regulation S-K, we have omitted certain subsidiaries (all of which, when considered in the aggregate as a single subsidiary, would not constitute a significant subsidiary as of the end of our last fiscal year).

PPW Holdings LLC	Delaware
PacifiCorp	Oregon
MidAmerican Funding, LLC	Iowa
MHC Inc.	Iowa
MidAmerican Energy Company	Iowa
NVE Holdings, LLC	Delaware
NV Energy, Inc.	Nevada
Nevada Power Company	Nevada
Sierra Pacific Power Company	Nevada
Northern Powergrid Holdings Company	United Kingdom
BHE Pipeline Group, LLC	Delaware
BHE GT&S, LLC	Delaware
Eastern Energy Gas Holdings, LLC	Virginia
Eastern MLP Holding Company II, LLC	Virginia
Cove Point LNG, LP	Maryland
BHE Canada Holdings Corporation	Canada
BHE U.S. Transmission, LLC	Delaware
BHE Renewables, LLC	Delaware
HomeServices of America, Inc.	Delaware

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-228511 on Form S-8 of our report dated February 25, 2022, relating to the financial statements and financial statement schedule of Berkshire Hathaway Energy Company appearing in this Annual Report on Form 10-K.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
February 25, 2022

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-249044 on Form S-3 of our report dated February 25, 2022, relating to the financial statements of PacifiCorp appearing in this Annual Report on Form 10-K.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 25, 2022

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-257069 on Form S-3 of our report dated February 25, 2022, relating to the financial statements of MidAmerican Energy Company appearing in this Annual Report on Form 10-K.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
February 25, 2022

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-234207 on Form S-3 of our report dated February 25, 2022 relating to the financial statements of Nevada Power Company appearing in this Annual Report on Form 10-K.

/s/ Deloitte & Touche LLP

Las Vegas, Nevada
February 25, 2022

EXHIBIT 24.1

POWER OF ATTORNEY

The undersigned, a member of the Board of Directors or an officer of BERKSHIRE HATHAWAY ENERGY COMPANY, an Iowa corporation (the "Company"), hereby constitutes and appoints Natalie L. Hocken and Jeffery B. Erb and each of them, as his/her true and lawful attorney-in-fact and agent, with full power of substitution and resubstitution, for and in his/her stead, in any and all capacities, to sign on his/her behalf the Company's Annual Report on Form 10-K for the fiscal year ending December 31, 2021 and to execute any amendments thereto and to file the same, with all exhibits thereto, and all other documents in connection therewith, with the Securities and Exchange Commission and applicable stock exchanges, with the full power and authority to do and perform each and every act and thing necessary or advisable to all intents and purposes as he/she might or could do in person, hereby ratifying and confirming all that said attorney-in-fact and agent, or his/her substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

Executed as of February 25, 2022

/s/ William J. Fehrman	/s/ Calvin D. Haack
WILLIAM J. FEHRMAN	CALVIN D. HAACK
/s/ Gregory E. Abel	/s/ Warren E. Buffett
GREGORY E. ABEL	WARREN E. BUFFETT
/s/ Marc D. Hamburg	
MARC D. HAMBURG	

EXHIBIT 31.1

CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002

I, William J. Fehrman, certify that:

1. I have reviewed this Annual Report on Form 10-K of Berkshire Hathaway Energy Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2022

/s/ William J. Fehrman
William J. Fehrman
President and Chief Executive Officer
(principal executive officer)

EXHIBIT 31.2

CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002

I, Calvin D. Haack, certify that:

1. I have reviewed this Annual Report on Form 10-K of Berkshire Hathaway Energy Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2022

/s/ Calvin D. Haack
Calvin D. Haack
Senior Vice President and Chief Financial Officer
(principal financial officer)

EXHIBIT 31.3

CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002

I, William J. Fehrman, certify that:

1. I have reviewed this Annual Report on Form 10-K of PacifiCorp;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: February 25, 2022

/s/ William J. Fehrman
William J. Fehrman
Chair of the Board of Directors and Chief Executive Officer
(principal executive officer)

EXHIBIT 31.4

CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002

I, Nikki L. Kobliha, certify that:

1. I have reviewed this Annual Report on Form 10-K of PacifiCorp;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2022

/s/ Nikki L. Kobliha
Nikki L. Kobliha
Vice President, Chief Financial Officer and Treasurer
(principal financial officer)

EXHIBIT 31.5

**CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002**

I, Kelcey A. Brown, certify that:

1. I have reviewed this Annual Report on Form 10-K of MidAmerican Energy Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2022

/s/ Kelcey A. Brown
Kelcey A. Brown
President and Chief Executive Officer
(principal executive officer)

EXHIBIT 31.6

CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002

I, Thomas B. Specketer, certify that:

1. I have reviewed this Annual Report on Form 10-K of MidAmerican Energy Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2022

/s/ Thomas B. Specketer
Thomas B. Specketer
Vice President and Chief Financial Officer
(principal financial officer)

EXHIBIT 31.7

CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002

I, Kelcey A. Brown, certify that:

1. I have reviewed this Annual Report on Form 10-K of MidAmerican Funding, LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2022

/s/ Kelcey A. Brown
Kelcey A. Brown
President
(principal executive officer)

EXHIBIT 31.8

**CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002**

I, Thomas B. Specketer, certify that:

1. I have reviewed this Annual Report on Form 10-K of MidAmerican Funding, LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2022

/s/ Thomas B. Specketer
Thomas B. Specketer
Vice President and Controller
(principal financial officer)

EXHIBIT 31.9

CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002

I, Douglas A. Cannon, certify that:

1. I have reviewed this Annual Report on Form 10-K of Nevada Power Company and its subsidiaries (dba NV Energy);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2022

/s/ Douglas A. Cannon
Douglas A. Cannon
President and Chief Executive Officer
(principal executive officer)

EXHIBIT 31.10

CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002

I, Michael E. Cole, certify that:

1. I have reviewed this Annual Report on Form 10-K of Nevada Power Company and its subsidiaries (dba NV Energy);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2022

/s/ Michael E. Cole
Michael E. Cole
Vice President, Chief Financial Officer and Treasurer
(principal financial officer)

EXHIBIT 31.11

CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002

I, Douglas A. Cannon, certify that:

1. I have reviewed this Annual Report on Form 10-K of Sierra Pacific Power Company and its subsidiaries (dba NV Energy);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2022

/s/ Douglas A. Cannon
Douglas A. Cannon
President and Chief Executive Officer
(principal executive officer)

EXHIBIT 31.12

CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002

I, Michael E. Cole, certify that:

1. I have reviewed this Annual Report on Form 10-K of Sierra Pacific Power Company and its subsidiaries (dba NV Energy);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2022

/s/ Michael E. Cole
Michael E. Cole
Vice President, Chief Financial Officer and Treasurer
(principal financial officer)

EXHIBIT 31.13

CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002

I, Paul E. Ruppert, certify that:

1. I have reviewed this Annual Report on Form 10-K of Eastern Energy Gas Holdings, LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2022

/s/ Paul E. Ruppert
Paul E. Ruppert
President
(principal executive officer)

EXHIBIT 31.14

**CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002**

I, Scott C. Miller, certify that:

1. I have reviewed this Annual Report on Form 10-K of Eastern Energy Gas Holdings, LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2022

/s/ Scott C. Miller
Scott C. Miller
Chief Financial Officer and Treasurer
(principal financial officer)

EXHIBIT 32.1

CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

I, William J. Fehrman, President and Chief Executive Officer of Berkshire Hathaway Energy Company (the "Company"), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of the Company for the annual period ended December 31, 2021 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 25, 2022

/s/ William J. Fehrman
William J. Fehrman
President and Chief Executive Officer
(principal executive officer)

EXHIBIT 32.2

CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

I, Calvin D. Haack, Senior Vice President and Chief Financial Officer of Berkshire Hathaway Energy Company (the "Company"), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of the Company for the annual period ended December 31, 2021 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 25, 2022

/s/ Calvin D. Haack
Calvin D. Haack
Senior Vice President and Chief Financial Officer
(principal financial officer)

EXHIBIT 32.3

CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

I, William J. Fehrman, Chair of the Board of Directors and Chief Executive Officer of PacifiCorp, certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of PacifiCorp for the annual period ended December 31, 2021 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PacifiCorp.

Date: February 25, 2022

/s/ William J. Fehrman
William J. Fehrman
Chair of the Board of Directors and Chief Executive Officer
(principal executive officer)

EXHIBIT 32.4

CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

I, Nikki L. Kobliha, Vice President, Chief Financial Officer and Treasurer of PacifiCorp, certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of PacifiCorp for the annual period ended December 31, 2021 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PacifiCorp.

Date: February 25, 2022

/s/ Nikki L. Kobliha
Nikki L. Kobliha
Vice President, Chief Financial Officer and Treasurer
(principal financial officer)

EXHIBIT 32.5

**CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002**

I, Kelcey A. Brown, President and Chief Executive Officer of MidAmerican Energy Company , certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of MidAmerican Energy Company for the annual period ended December 31, 2021 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of MidAmerican Energy Company.

Date: February 25, 2022

/s/ Kelcey A. Brown
Kelcey A. Brown
President and Chief Executive Officer
(principal executive officer)

EXHIBIT 32.6

CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

I, Thomas B. Specketer, Vice President and Chief Financial Officer of MidAmerican Energy Company, certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of MidAmerican Energy Company for the annual period ended December 31, 2021 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of MidAmerican Energy Company.

Date: February 25, 2022

/s/ Thomas B. Specketer
Thomas B. Specketer
Vice President and Chief Financial Officer
(principal financial officer)

EXHIBIT 32.7

CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

I, Kelcey A. Brown, President of MidAmerican Funding, LLC, certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of MidAmerican Funding, LLC for the annual period ended December 31, 2021 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of MidAmerican Funding, LLC.

Date: February 25, 2022

/s/ Kelcey A. Brown
Kelcey A. Brown
President
(principal executive officer)

EXHIBIT 32.8

CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

I, Thomas B. Specketer, Vice President and Controller of MidAmerican Funding, LLC, certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of MidAmerican Funding, LLC for the annual period ended December 31, 2021 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of MidAmerican Funding, LLC.

Date: February 25, 2022

/s/ Thomas B. Specketer
Thomas B. Specketer
Vice President and Controller
(principal financial officer)

EXHIBIT 32.9

CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

I, Douglas A. Cannon, President and Chief Executive Officer of Nevada Power Company and its subsidiaries (dba NV Energy), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of Nevada Power Company and its subsidiaries for the annual period ended December 31, 2021 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Nevada Power Company and its subsidiaries.

Date: February 25, 2022

/s/ Douglas A. Cannon
Douglas A. Cannon
President and Chief Executive Officer
(principal executive officer)

EXHIBIT 32.10

CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

I, Michael E. Cole, Vice President, Chief Financial Officer and Treasurer of Nevada Power Company and its subsidiaries (dba NV Energy), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of Nevada Power Company and its subsidiaries for the annual period ended December 31, 2021 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Nevada Power Company and its subsidiaries.

Date: February 25, 2022

/s/ Michael E. Cole
Michael E. Cole
Vice President, Chief Financial Officer and Treasurer
(principal financial officer)

EXHIBIT 32.11

CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

I, Douglas A. Cannon, President and Chief Executive Officer of Sierra Pacific Power Company and its subsidiaries (dba NV Energy), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of Sierra Pacific Power Company and its subsidiaries for the annual period ended December 31, 2021 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Sierra Pacific Power Company and its subsidiaries.

Date: February 25, 2022

/s/ Douglas A. Cannon
Douglas A. Cannon
President and Chief Executive Officer
(principal executive officer)

EXHIBIT 32.12

CERTIFICATION PURSUANT TO

SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

I, Michael E. Cole, Vice President, Chief Financial Officer and Treasurer of Sierra Pacific Power Company and its subsidiaries (dba NV Energy), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of Sierra Pacific Power Company and its subsidiaries for the annual period ended December 31, 2021 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Sierra Pacific Power Company and its subsidiaries.

Date: February 25, 2022

/s/ Michael E. Cole
Michael E. Cole
Vice President, Chief Financial Officer and Treasurer
(principal financial officer)

EXHIBIT 32.13

**CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002**

I, Paul E. Ruppert, President of Eastern Energy Gas Holdings, LLC, certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of Eastern Energy Gas Holdings, LLC for the annual period ended December 31, 2020 (the "Report") fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of Eastern Energy Gas Holdings, LLC.

Date: February 25, 2022

/s/ Paul E. Ruppert
Paul E. Ruppert
President
(principal executive officer)

EXHIBIT 32.14

CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

I, Scott C. Miller, Chief Financial Officer and Treasurer of Eastern Energy Gas Holdings, LLC, certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of Eastern Energy Gas Holdings, LLC for the annual period ended December 31, 2020 (the "Report") fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of Eastern Energy Gas Holdings, LLC.

Date: February 25, 2022

/s/ Scott C. Miller
Scott C. Miller
Chief Financial Officer and Treasurer
(principal financial officer)

EXHIBIT 95

MINE SAFETY VIOLATIONS AND OTHER LEGAL MATTER DISCLOSURES PURSUANT TO SECTION 1503(a) OF THE DODD-FRANK WALL STREET REFORM AND CONSUMER PROTECTION ACT

PacifiCorp and its subsidiaries operate certain coal mines and coal processing facilities (collectively, the "mining facilities") that are regulated by the Federal Mine Safety and Health Administration ("MSHA") under the Federal Mine Safety and Health Act of 1977 (the "Mine Safety Act"). MSHA inspects PacifiCorp's mining facilities on a regular basis. The total number of reportable Mine Safety Act citations, orders, assessments and legal actions for the year ended December 31, 2021 are summarized in the table below and are subject to contest and appeal. The severity and assessment of penalties may be reduced or, in some cases, dismissed through the contest and appeal process. Amounts are reported regardless of whether PacifiCorp has challenged or appealed the matter. Mines that are closed or idled are not included in the information below as no reportable events occurred at those locations during the year ended December 31, 2021. There were no mining-related fatalities during the year ended December 31, 2021. PacifiCorp has not received any notice of a pattern, or notice of the potential to have a pattern, of violations of mandatory health or safety standards that are of such nature as could have significantly and substantially contributed to the cause and effect of coal or other mine health or safety hazards under Section 104(e) of the Mine Safety Act during the year ended December 31, 2021.

	Mine Safety Act						Legal Actions		
Mining Facilities	**Section 104 Significant and Substantial Citations[1]**	**Section 104(b) Orders[2]**	**Section 104(d) Citations/ Orders[3]**	**Section 110(b)(2) Violations[4]**	**Section 107(a) Imminent Danger Orders[5]**	**Total Value of Proposed MSHA Assessments (in thousands)**	**Pending as of Last Day of Period[6]**	**Instituted During Period**	**Resolved During Period**
Bridger (surface)	1	—	—	—	—	$ 1	1	1	—
Bridger (underground)	7	—	—	—	—	42	1	2	2
Wyodak Coal Crushing Facility	—	—	—	—	—	—	—	—	—

(1) Citations for alleged violations of mandatory health and safety standards that could significantly or substantially contribute to the cause and effect of a safety or health hazard under Section 104 of the Mine Safety Act.

(2) For alleged failure to totally abate the subject matter of a Mine Safety Act Section 104(a) citation within the period specified in the citation.

(3) For alleged unwarrantable failure (i.e., aggravated conduct constituting more than ordinary negligence) to comply with a mandatory health or safety standard.

(4) For alleged flagrant violations (i.e., reckless or repeated failure to make reasonable efforts to eliminate a known violation of a mandatory health or safety standard that substantially and proximately caused, or reasonably could have been expected to cause, death or serious bodily injury).

(5) For the existence of any condition or practice in a coal or other mine which could reasonably be expected to cause death or serious physical harm before such condition or practice can be abated.

(6) Amounts include two contests of proposed penalties under Subpart C of the Federal Mine Safety and Health Review Commission's procedural rules. The pending legal actions are not exclusive to citations, notices, orders and penalties assessed by MSHA during the reporting period.

Appendix B

Berkshire Hathaway, Inc.'s Definitive Proxy Statement (DEF 14A)

Filed with the Securities and Exchange Commission on March 11, 2022

BERKSHIRE HATHAWAY INC.

3555 Farnam Street
Omaha, Nebraska 68131

NOTICE OF ANNUAL MEETING OF SHAREHOLDERS

April 30, 2022

TO THE SHAREHOLDERS:

Notice is hereby given that the Annual Meeting of the Shareholders of Berkshire Hathaway Inc. will be held at the CHI Health Center, 455 North 10th Street, Omaha, Nebraska, on April 30, 2022 at 3:45 p.m. for the following purposes:

1. To elect directors.
2. To act on four shareholder proposals if properly presented at the meeting.
3. To consider and act upon any other matters that may properly come before the meeting or any adjournment thereof.

The Board of Directors has fixed the close of business on March 2, 2022 as the record date for determining the shareholders having the right to vote at the meeting or any adjournment thereof. A list of such shareholders will be available for examination by a shareholder for any purpose germane to the meeting during ordinary business hours at the offices of the Corporation at 3555 Farnam Street, Omaha, Nebraska, during the ten days prior to the meeting.

Your vote is important. Regardless of whether you plan to participate in the Annual Meeting, we hope you will vote as soon as possible. Voting will ensure you are represented at the Annual Meeting, regardless of whether you plan to attend the Annual Meeting. You may cast your vote over the Internet, by telephone, by mail or during the Annual Meeting.

Prior to the formal Annual Meeting, the doors will open at the CHI Health Center at 7:00 a.m. and the movie will be shown at 8:30 a.m. At 9:15 a.m., the question and answer period will commence. The question and answer period will last until 3:30 p.m. (with a short break for lunch). After a recess, the formal Annual Meeting of Shareholders will convene at 3:45 p.m.

By order of the Board of Directors

MARC D. HAMBURG, *Secretary*

Omaha, Nebraska
March 11, 2022

A shareholder may request meeting credentials for admission to the meeting by completing and promptly returning to the Company the meeting credential order form accompanying this notice. Otherwise, meeting credentials may be obtained at the meeting by persons identifying themselves as shareholders as of the record date. Possession of a proxy card, a voting information form received from a bank or broker or a broker's statement showing shares owned on March 2, 2022 along with proper identification will be required.

IMPORTANT NOTICE REGARDING THE AVAILABILITY OF PROXY MATERIALS FOR THE SHAREHOLDER MEETING TO BE HELD ON APRIL 30, 2022.

The Proxy Statement for the Annual Meeting of Shareholders to be held on April 30, 2022 and the 2021 Annual Report to the Shareholders are available at www.berkshirehathaway.com/eproxy.

BERKSHIRE HATHAWAY INC.
3555 Farnam Street
Omaha, Nebraska 68131

PROXY STATEMENT
FOR ANNUAL MEETING OF SHAREHOLDERS
April 30, 2022

This statement is furnished in connection with the solicitation by the Board of Directors ("Board") of Berkshire Hathaway Inc. (hereinafter "Berkshire" or "Corporation" or "Company") of proxies in the accompanying form for the Annual Meeting of Shareholders to be held on Saturday, April 30, 2022 at 3:45 p.m. and at any adjournment thereof. This proxy statement and the enclosed form of proxy were first sent to shareholders on or about March 11, 2022. If the form of proxy enclosed herewith is executed and returned as requested, it may nevertheless be revoked at any time prior to exercise by filing an instrument revoking it or a duly executed proxy bearing a later date. Solicitation of proxies will be made at the Corporation's expense. The Corporation will reimburse brokerage firms, banks, trustees and others for their actual out-of-pocket expenses in forwarding proxy material to the beneficial owners of its common stock.

As of the close of business on March 2, 2022, the record date for the Annual Meeting, the Corporation had outstanding and entitled to vote 614,692 shares of Class A Common Stock (hereinafter called "Class A Stock") and 1,287,633,719 shares of Class B Common Stock (hereinafter called "Class B Stock"). Each share of Class A Stock is entitled to one vote per share and each share of Class B Stock is entitled to one-ten-thousandth (1/10,000) of one vote per share on all matters submitted to a vote of shareholders of the Corporation. The Class A Stock and Class B Stock vote together as a single class on the matters described in this proxy statement. Only shareholders of record at the close of business on March 2, 2022 are entitled to vote at the Annual Meeting or at any adjournment thereof.

The presence at the meeting, in person or by proxy, of the holders of Class A Stock and Class B Stock holding in the aggregate a majority of the voting power of the Corporation's stock entitled to vote shall constitute a quorum for the transaction of business. A plurality of the votes properly cast for the election of directors by the shareholders attending the meeting, in person or by proxy, will elect directors to office. However, pursuant to the Berkshire Hathaway Inc. Corporate Governance Guidelines, if a director nominee in an uncontested election receives a greater number of votes "withheld" from his or her election than votes "for" that director's election, the nominee shall promptly offer his or her resignation to the Board. A committee consisting of the Board's independent directors (which will specifically exclude any director who is required to offer his or her own resignation) shall consider all relevant factors and decide on behalf of the Board the action to be taken with respect to such offered resignation and will determine whether to accept the resignation or take other action. The Corporation will publicly disclose the Board's decision with regard to any resignation offered under these circumstances with an explanation of how the decision was reached, including, if applicable, the reasons for rejecting the offered resignation.

A majority of votes properly cast upon any other question shall decide the question. Abstentions will count for purposes of establishing a quorum, but will not count as votes cast for the election of directors or any other question. Accordingly, abstentions will have no effect on the election of directors and are the equivalent of an "against" vote on matters requiring a majority of votes properly cast to decide the question. Broker non-votes will not count for purposes of establishing a quorum or as votes cast for the election of directors or any other question and accordingly will have no effect. Shareholders who submit proxies prior to the meeting but attend the meeting in person may vote directly if they prefer and withdraw their proxies or may allow their proxies to be voted with the similar proxies submitted by other shareholders. Your vote is very important. Whether or not you plan to view the Annual Meeting, please vote at your earliest convenience by following the instructions in the Notice of Internet Availability of Proxy Materials, voting instruction form or the proxy card you received.

IMPORTANT NOTICE REGARDING THE AVAILABILITY OF PROXY MATERIALS FOR THE SHAREHOLDER MEETING TO BE HELD ON APRIL 30, 2022.

The Proxy Statement for the Annual Meeting of Shareholders to be held on April 30, 2022 and the 2021 Annual Report to the Shareholders are available at www.berkshirehathaway.com/eproxy.

1. ELECTION OF DIRECTORS

At the 2022 Annual Meeting of Shareholders, a Board of Directors consisting of 15 members will be elected, each director to hold office until a successor is elected and qualified, or until the director resigns, is removed or becomes disqualified.

The Governance, Compensation and Nominating Committee ("Governance Committee") has established certain attributes that it seeks in identifying candidates for directors. In particular, the Governance Committee looks for individuals who have very high integrity, business savvy, an owner-oriented attitude and a deep genuine interest in Berkshire. These are the same attributes that Warren Buffett, Berkshire's Chairman and CEO, believes to be essential if one is to be an effective member of the Board of Directors. In considering candidates for director, the Governance Committee considers the entirety of each candidate's credentials in the context of these attributes. In the judgment of the Governance Committee as well as that of the Board as a whole, each of the candidates being nominated for director possesses such attributes.

Upon the recommendation of the Governance Committee and Mr. Buffett, the Board of Directors has nominated for election the 14 current directors of the Corporation and Mr. Wallace R. Weitz. Mr. Thomas S. Murphy served as director of the Corporation until his resignation on February 14, 2022. Certain information with respect to nominees for election as directors follows:

WARREN E. BUFFETT, age 91, has been a director and the controlling shareholder of the Corporation since 1965 and has been its Chairman and Chief Executive Officer since 1970. Mr. Buffett was a director of The Kraft Heinz Company until April 2018.

Additional Qualifications:

Warren Buffett brings to the Board his 52 years of experience as Chairman and Chief Executive Officer of the Corporation.

GREGORY E. ABEL, age 59, was elected a director of the Corporation and the Corporation's Vice Chairman – Non Insurance Operations on January 9, 2018. Between 2008 and January 9, 2018, Mr. Abel served as the Chief Executive Officer of Berkshire Hathaway Energy Company ("BHE"), a 91% owned subsidiary of Berkshire. Mr. Abel has served as BHE's Chairman since 2011. Mr. Abel also serves as a director of The Kraft Heinz Company and AEGIS Insurance Services Inc., a provider of property and liability insurance for the energy industry.

Additional Qualifications:

Gregory Abel brings to the Board his 29 years of experience in various positions at BHE, including serving as its Chairman and CEO. He also brings to the Board his experience as a director of The Kraft Heinz Company.

HOWARD G. BUFFETT, age 67, has been a director of the Corporation since 1993. Since 2013, Mr. Buffett has been the Chairman and Chief Executive Officer of the Howard G. Buffett Foundation, a charitable foundation that directs funding for humanitarian and conservation related issues. Between 1999 and 2013, he served as the President of the Howard G. Buffett Foundation. Mr. Buffett was the Sheriff of Macon County, Illinois between September 2017 and December 2018. He was a director of The Coca-Cola Company until April 2017.

Additional Qualifications:

Howard Buffett brings to the Board his experience as the owner of a small business, as a past senior executive of a public corporation, as a former director of other public corporations and as the Chairman and CEO of a large charitable foundation.

SUSAN A. BUFFETT, age 68, was elected a director of the Corporation on October 20, 2021. For more than the past five years, she has been the Chairman of the Sherwood Foundation and the Chairman of the Susan Thompson Buffett Foundation, each of which is a private grant-making foundation based in Omaha, NE. Ms. Buffett also serves on the board of several other charitable organizations.

Additional Qualifications:

Susan Buffett brings to the Board her experience as the board chair of two large charitable foundations and as a board member of several other charitable organizations.

STEPHEN B. BURKE, age 63, has been a director of the Corporation since 2009. Mr. Burke was the Chairman of NBCUniversal between January 2020 and August 2020 and he was the Chief Executive Officer of NBCUniversal and Senior Executive Vice President of Comcast Corporation between January 2011 and January 2020. From 1998 until 2011, he was the Chief Operating Officer of Comcast Corporation. He is also a director of JPMorgan Chase & Co.

Additional Qualifications:

Stephen Burke brings to the Board his experience as a senior executive of a public corporation and his financial expertise as a director of a major banking institution.

KENNETH I. CHENAULT, age 70, was elected a director of the Corporation on May 2, 2020. Mr. Chenault has served as Chairman and a Managing Director of General Catalyst, a venture capital firm, since February 2018. Mr. Chenault previously served as Chief Executive Officer of American Express Company, a financial services company, from January 2001 to February 2018, and as Chairman of American Express Company from April 2001 to February 2018. Mr. Chenault joined American Express in 1981 as Director of Strategic Planning and served subsequently in a number of increasingly senior positions, including Vice Chairman and President and Chief Operating Officer, until his appointment as Chief Executive Officer. Mr. Chenault is a director of Airbnb, a global platform for unique stays and experiences. Mr. Chenault previously served on the boards of directors of Facebook Inc. from February 2018 to May 2020, International Business Machines Corporation from October 1998 to February 2019 and The Procter & Gamble Company from April 2008 to February 2019.

Additional Qualifications:

Kenneth Chenault brings to the Board his experience and financial expertise as a past chief executive officer of a large financial services public corporation and a director of other public corporations.

CHRISTOPHER C. DAVIS, age 56, was elected a director on October 20, 2021. Since 1998, he has served as the Chairman of Davis Advisors, an investment management and counseling firm. Mr. Davis is also a director of a number of mutual funds advised by Davis Select Advisors as well as other entities controlled by Davis Select Advisors. He is also a director of The Coca-Cola Company and Graham Holdings Company.

Additional Qualifications:

Christopher Davis brings to the Board his experience and financial expertise as the chairman of a large investment management and counseling firm and as a director of two public corporations.

SUSAN L. DECKER, age 59, has been a director of the Corporation since 2007. Ms. Decker also serves on the boards of directors of Costco Wholesale Corporation, Vail Resorts, Inc., Momentive, Chime, Automattic and Vox Media. She is CEO and Founder of Raftr, a community-building and insights platform for university students and administrations. From June 2000 to April 2009, Ms. Decker held various executive management positions at Yahoo! Inc., a global Internet brand, including President (June 2007 to April 2009), head of the Advertiser and Publisher Group (December 2006 to June 2007) and Chief Financial Officer (June 2000 to June 2007). Before Yahoo!, Ms. Decker spent 14 years with Donaldson, Lufkin & Jenrette. She is a Chartered Financial Analyst and served on the Financial Accounting Standards Advisory Council for a four-year term, from 2000 to 2004.

Additional Qualifications:

Susan Decker brings to the Board her experience as a past senior executive of a public corporation and a director of public corporations and her financial expertise as a former equity securities analyst and a former member of the Financial Accounting Standards Advisory Council.

DAVID S. GOTTESMAN, age 95, has been a director of the Corporation since 2004. For more than the past five years, he has been a principal of First Manhattan Co., an investment advisory firm. Mr. Gottesman is Vice Chairman and a trustee of the American Museum of Natural History and a trustee of Mount Sinai Medical Center.

Additional Qualifications:

David Gottesman brings to the Board his experience and financial expertise as principal of a private investment manager.

CHARLOTTE GUYMAN, age 65, has been a director of the Corporation since 2003. Ms. Guyman is co-founder of BoardReady, a not-for-profit corporation whose mission is to catapult board diversification through data, experience and network strategies. Ms. Guyman is currently a strategic advisor to Cameoworks, a global retail and financial services advisory firm. She was a general manager with Microsoft Corporation until July 1999. She is a director of Space Needle LLC and Glass and Pro.com. She was former Chairman of the Board of Directors of UW Medicine, an academic medical center.

Additional Qualifications:

Charlotte Guyman brings to the Board her experience as a past senior executive of a public corporation and her financial expertise as the former chairman of a major academic medical center.

AJIT JAIN, age 70, was elected a director of the Corporation and its Vice Chairman – Insurance Operations on January 9, 2018. Mr. Jain has been employed by the Berkshire Hathaway Insurance Group since 1986 and has been an Executive Vice President of National Indemnity Company, a wholly owned Berkshire subsidiary, since 1996.

Additional Qualifications:

Ajit Jain brings to the Board his 35 years of experience in managing Berkshire's reinsurance operations, one of its most important businesses. During this period he has been responsible for overseeing the assessment and pricing of many of the largest and most complex risks ever insured and as a result generating billions of dollars of capital for deployment by the Corporation.

CHARLES T. MUNGER, age 98, has been a director and Vice Chairman of the Corporation's Board of Directors since 1978. Between 1984 and 2011, he was Chairman of the Board of Directors and Chief Executive Officer of Wesco Financial Corporation, approximately 80% owned by the Corporation during that period. He also served as President of Wesco Financial Corporation between 2005 and 2011. Mr. Munger is also Chairman of the Board of Directors of Daily Journal Corporation and a director of Costco Wholesale Corporation.

Additional Qualifications:

Charles Munger brings to the Board his 43 years of experience as Vice Chairman of the Corporation.

RONALD L. OLSON, age 80, has been a director of the Corporation since 1997. For more than the past five years, he has been a partner in the law firm of Munger, Tolles & Olson LLP. He is a Trustee of Western Asset Trusts, a Trustee of California Institute of Technology and a director of Provivi, an emerging crop protection company. Mr. Olson was also a director of Graham Holdings Company until May 2017.

Additional Qualifications:

Ronald Olson brings to the Board his experience and expertise in legal issues and corporate governance as a partner of a law firm and as a former director of public corporations.

WALLACE R. WEITZ, age 72, has been nominated to fill a vacancy on the Board. Mr. Weitz founded the investment management firm Weitz Investment Management, Inc. in 1983 as Wallace R. Weitz & Company and has since served in various roles at Weitz Investment Management, including Chief Investment Officer, President and Portfolio Manager. Mr. Weitz manages the Partners III Opportunity Fund and co-manages the Partners Value Fund and Hickory Fund, each of which is managed by Weitz Investment Management. He has served as a Trustee of the Weitz Funds since 1986. Mr. Weitz began his career in New York as a securities analyst before joining Chiles, Heider & Co. in Omaha, Nebraska in 1973. He is on the Board of Directors of Cable One, a leading broadband communication provider. Mr. Weitz is also on the board of trustees for Carleton College and serves on various other non-profit boards.

Additional Qualifications:

Wallace Weitz brings to the Board his substantial financial experience as an investor in public companies and as a director of a public company.

MERYL B. WITMER, age 60, has been a director of the Corporation since 2013. For more than the past five years, Ms. Witmer has been a managing member of the General Partner of Eagle Capital Partners, L.P., an investment partnership. From 1989 through the end of 2000, she was one of two General Partners at Buchanan Parker Asset Management which managed Emerald Partners L.P., an investment partnership. Ms. Witmer is a director of University of Virginia Investment Management Company.

Additional Qualifications:

Meryl Witmer brings to the Board her experience and financial expertise as a manager of an investment fund.

When the accompanying proxy is properly executed and submitted, the shares it represents will be voted in accordance with the directions indicated thereon or, if no direction is indicated, the shares will be voted in favor of the election of the 15 nominees identified above. The Corporation expects each nominee to be able to serve if elected, but if any nominee notifies the Corporation before the Annual Meeting that he or she is unable to do so, then the proxies will be voted for the remainder of those nominated and, as designated by the directors, may be voted (i) for a substitute nominee or nominees or (ii) to elect such lesser number to constitute the whole Board as equals the number of nominees who are able to serve.

Directors' Independence

The Governance Committee of the Board of Directors has concluded that the following directors are independent in accordance with the director independence standards of the Securities and Exchange Commission pursuant to Item 407(a) of Regulation S-K and has determined that none of them has a material relationship with the Corporation that would impair his or her independence from management or otherwise compromise his or her ability to act as an independent director: Stephen B. Burke; Kenneth I. Chenault; Christopher C. Davis; Susan L. Decker; David S. Gottesman; Charlotte Guyman; Meryl B. Witmer; and Wallace R. Weitz. Additionally, the Governance Committee concluded that Walter Scott, Jr., who served as a director until his death on September 25, 2021, and Thomas S. Murphy, who served as a director until his resignation on February 14, 2022, were independent in accordance with the same standards.

Howard G. Buffett and Susan A. Buffett are children of Warren Buffett. Ronald L. Olson is a partner of the law firm of Munger, Tolles & Olson LLP. Munger, Tolles & Olson LLP rendered legal services to the Corporation and its subsidiaries in 2021 and has been rendering services in 2022. The Corporation and its subsidiaries paid fees of $7.9 million to Munger, Tolles & Olson LLP during 2021.

Board of Directors' Leadership Structure and Role in Risk Oversight

Warren E. Buffett is Berkshire's Chief Executive Officer and Chairman of the Board of Directors. He is Berkshire's largest shareholder and owns shares of Berkshire that represent approximately 32.1% of the voting interest and 16.2% of the economic interest. As such he may be deemed to be Berkshire's controlling shareholder. It is Mr. Buffett's opinion that a controlling shareholder who is active in the business, as is currently the case and has been the case for Mr. Buffett for over 50 years, should hold both roles. This opinion is shared by Berkshire's Board of Directors. On September 30, 2021, the independent directors named Susan L. Decker as lead independent director.

Mr. Buffett and the other members of the Board of Directors extensively discuss succession planning at each meeting of the Board. Upon his death or inability to manage Berkshire, no member of the Buffett family will be involved in managing Berkshire but, as very substantial Berkshire shareholders, the Buffett family will assist the Board of Directors in picking and overseeing the CEO selected to succeed Mr. Buffett. At that time, Mr. Buffett believes it would be prudent to have a member of the Buffett family serve as the non-executive Chairman of the Board. Ultimately, however, that decision will be the responsibility of the then Board of Directors.

The full Board of Directors has responsibility for general oversight of risks. It receives reports from Mr. Buffett and other members of senior management at least twice a year on areas of risk facing the Corporation. In addition, as part of its charter, the Audit Committee discusses Berkshire's policies with respect to risk assessment and risk management.

Board of Directors' Meetings

Board of Directors' actions were taken in 2021 at the Annual Meeting of Directors that followed the 2021 Annual Meeting of Shareholders and at two special meetings and upon one occasion by directors' unanimous written consent. Each then current director attended all meetings of the Board and of the Committees of the Board on which he or she served. Directors are encouraged but not required to attend annual meetings of the Corporation's shareholders.

Meetings of Independent Directors

Two meetings of independent directors were held during 2021. At the first of the two meetings of independent directors, Susan L. Decker was named lead independent director and presided over each of the meetings. A shareholder or other interested party wishing to contact the non-management directors or independent directors, as applicable, should send a letter to the Secretary of the Corporation at 3555 Farnam Street, Omaha, NE 68131. The mailing envelope must contain a clear notation that the enclosed letter is to be forwarded to the Corporation's non-management directors or independent directors, as applicable.

Board of Directors' Committees

The Board of Directors has established an Audit Committee in accordance with Section 3(a)(58)A of the Securities Exchange Act of 1934. During 2021, the Audit Committee consisted of Susan L. Decker, Charlotte Guyman, Thomas S. Murphy and Meryl B. Witmer. The Board of Directors has determined that Ms. Decker is an "audit committee financial expert" as that term is used in Item 401(h) of Regulation S-K promulgated under the Securities Exchange Act. On January 13, 2022, Christopher C. Davis replaced Ms. Guyman as a member of the Audit Committee. As previously disclosed, Mr. Murphy resigned from the Board of Directors on February 14, 2022. All current members of the Audit Committee as well as Ms. Guyman and Mr. Murphy meet the criteria for independence set forth in Rule 10A-3 under the Securities Exchange Act and in Section 303A of the New York Stock Exchange Listed Company Manual. The Audit Committee assists the Board with oversight of a) the integrity of the Corporation's financial statements, b) the Corporation's compliance with legal and regulatory requirements and c) the qualifications and independence of the Corporation's independent public accountants and internal audit function. The Audit Committee meets periodically with the Corporation's independent public accountants, Director of Internal Auditing and members of management and reviews the Corporation's accounting policies and internal controls. The Audit Committee also selects the firm of independent public accountants to be retained by the Corporation to perform the audit. The Audit Committee held six meetings during 2021. The Board of Directors adopted an Audit Committee Charter on April 29, 2000, which was subsequently amended and restated on March 2, 2004. The amended Audit Committee Charter is available on Berkshire's website at www.berkshirehathaway.com.

The Board of Directors has established a Governance Committee and adopted a Charter to define and outline the responsibilities of its members. A copy of the Governance Committee's Charter is available on Berkshire's website at www.berkshirehathaway.com. The Governance Committee currently consists of Stephen B. Burke, Kenneth I. Chenault, David S. Gottesman and Charlotte Guyman, all of whom are independent directors in accordance with the New York Stock Exchange director independence standards.

The role of the Governance Committee is to assist the Board of Directors by a) recommending governance guidelines applicable to Berkshire; b) identifying, evaluating and recommending the nomination of Board members; c) setting the compensation of Berkshire's Chief Executive Officer and performing other compensation oversight; and d) assisting the Board with other related tasks, as assigned from time to time. The Governance Committee met once during 2021.

Director Nominations

Berkshire does not have a policy regarding the consideration of diversity in identifying nominees for director. In identifying director nominees, the Governance Committee does not seek diversity, however defined. Instead, as previously discussed, the Governance Committee looks for individuals who have very high integrity, business savvy, an owner-oriented attitude and a deep genuine interest in the Company. With respect to the selection of director nominees at the 2022 Annual Meeting of Shareholders, the Governance Committee recommends the Board nominate the 14 directors currently serving on the Board as well as Mr. Weitz.

Berkshire's Governance Committee has a policy under which it will consider director recommendations presented by shareholders. A shareholder wishing to submit such a recommendation should send a letter to the Secretary of the Corporation at 3555 Farnam Street, Omaha, NE 68131. The mailing envelope must contain a clear notation that the enclosed letter is a "Director Nominee Recommendation." The Secretary must receive the recommendation by December 15, 2022, for it to be considered by the Committee for the 2023 Annual Meeting of Shareholders. The letter must identify the author as a shareholder and provide a brief summary of the candidate's qualifications. At a minimum, candidates recommended for nomination to the Board of Directors must meet the director independence standards of the New York Stock Exchange. The Governance Committee's policy provides that candidates recommended by shareholders will be evaluated using the same criteria as are applied to all other candidates. In particular, any recommended candidate should own Berkshire stock that has represented a substantial portion of the candidate's investment portfolio for at least three years.

Code of Business Conduct and Ethics

The Corporation has adopted a Code of Business Conduct and Ethics for all Berkshire directors, officers and employees as well as directors, officers and employees of each of its subsidiaries. The Code of Business Conduct and Ethics is available on Berkshire's website at www.berkshirehathaway.com.

Related Persons Transactions

The Charter of the Audit Committee requires that the Audit Committee approve or ratify any Related Persons Transaction ("Transaction") as defined in the regulations of the Securities and Exchange Commission. The Audit Committee has established procedures that require that all requests for approval of proposed Transactions or ratification of Transactions be referred to the Chairman of the Audit Committee or directly to the full committee. The full committee reviews any Transaction which the Chairman concludes is material to the Company or which the Chairman is unable to review. Only Transactions which the Audit Committee or its Chairman finds to be in the best interests of Berkshire and its stockholders are approved or ratified. The Chairman reports all Transactions which he reviews to the Audit Committee annually for ratification.

Mr. Abel currently is the holder of approximately 1% of the voting stock of Berkshire Hathaway Energy Company ("BHE") in which the Corporation owns approximately 91% of the voting stock. The family members of Walter Scott, who was a Berkshire director until his death in September 2021, and related entities (the "Walter Scott Interests") own approximately 8% of the voting stock of BHE. Mr. Abel as well as the Walter Scott Interests have each entered into an agreement with the Corporation that requires Mr. Abel or the Walter Scott Interests prior to selling any BHE shares to give the Corporation the right to purchase the shares (if the Corporation is legally permitted to buy them) or to assign its right to purchase to a third party (if not legally permitted to buy them). That same agreement gives Mr. Abel and the Walter Scott Interests the right to put their shares to the Corporation (if the Corporation is legally permitted to buy them) at fair market value to be determined by independent appraisal if the sellers do not agree with the price offered by the Corporation, and payable in Berkshire shares. In addition, Mr. Abel can also put his shares to BHE ("BHE Put") and BHE can call Mr. Abel's shares ("BHE Call"). The purchase price under the BHE Put or BHE Call shall be payable in cash and determined in the same manner as described above.

Governance, Compensation and Nominating Committee Interlocks and Insider Participation

The Governance Committee of our Board of Directors currently consists of Charlotte Guyman, Stephen B. Burke, Kenneth I. Chenault and David S. Gottesman. None of these individuals has at any time been an officer or employee of the Company. During 2021, none of our executive officers served as a member of the board of directors or compensation committee of any entity for which a member of our Board of Directors served as an executive officer.

Corporate Governance Guidelines

The Board of Directors has adopted Corporate Governance Guidelines to promote effective governance of the Corporation. The Corporate Governance Guidelines are available on Berkshire's website at www.berkshirehathaway.com.

Director Compensation

Directors of the Corporation or its subsidiaries who are employees or spouses of employees do not receive fees for attendance at directors' meetings. A director who is not an employee or a spouse of an employee receives a fee of $900 for each meeting attended in person and $300 for participating in any meeting conducted by telephone. A director who serves as a member of the Audit Committee receives a fee of $1,000 quarterly. Directors are reimbursed for their out-of-pocket expenses incurred in attending meetings of directors or shareholders. The Company does not provide directors and officers liability insurance to its directors.

The following table provides compensation information for the year ended December 31, 2021 for each non-management member who was a member of the Corporation's Board of Directors during 2021.

	Fees Earned or Paid in Cash	Total
Howard G. Buffett	$2,100	$2,100
Susan A. Buffett	—	—
Stephen B. Burke	2,100	2,100
Kenneth I. Chenault	900	900
Christopher C. Davis	—	—
Susan L. Decker	6,100	6,100
David S. Gottesman	900	900
Charlotte Guyman	6,100	6,100
Thomas S. Murphy	4,900	4,900
Ronald L. Olson	2,100	2,100
Walter Scott, Jr.	300	300
Meryl B. Witmer	6,100	6,100

Compensation Discussion and Analysis

Berkshire's program regarding compensation of its executive officers is different from most public company programs. Mr. Buffett's and Mr. Munger's compensation is reviewed annually by the Governance Committee of the Corporation's Board of Directors. Due to Mr. Buffett's and Mr. Munger's desire that their compensation remain unchanged, the Committee has not proposed an increase in Mr. Buffett's or Mr. Munger's compensation since the Committee was created in 2004. Prior to that time, Mr. Buffett recommended to the Board of Directors the amount of his compensation and Mr. Munger's. Mr. Buffett's annual compensation and Mr. Munger's annual compensation have been $100,000 for more than 25 years and Mr. Buffett has advised the Committee that he would not expect or desire such compensation to increase in the future.

The Committee has established a policy that neither the profitability of Berkshire nor the market value of its stock are to be considered in the compensation of any executive officer. Under the Committee's compensation policy, Berkshire does not grant stock options to executive officers. The Committee has delegated to Mr. Buffett the responsibility for setting the compensation of Mr. Abel, Vice Chairman-Non Insurance Operations, Mr. Jain, Vice Chairman-Insurance Operations and Marc Hamburg, Berkshire's Senior Vice President/Chief Financial Officer and Secretary.

Mr. Buffett will on occasion utilize Berkshire personnel and/or have Berkshire pay for minor items such as postage or phone calls that are personal. Mr. Buffett reimburses Berkshire for these costs by making an annual payment to Berkshire in an amount that is equal to or greater than the costs that Berkshire has incurred on his behalf. During 2021, Mr. Buffett reimbursed Berkshire $50,000. Berkshire provides personal and home security services for Mr. Buffett. The cost for these services was $273,204 in 2021. Berkshire's Board of Directors believe that in light of Mr. Buffett's critical role as Berkshire's CEO and given that Mr. Buffett spends a significant amount of his time while at home on Berkshire business matters that such costs represent bona fide business expenses. None of Berkshire's named executive officers use Company cars or belong to clubs to which the Company pays dues. It should also be noted that neither Mr. Buffett nor Mr. Munger utilize corporate-owned aircraft for personal use. Each of them is personally a fractional NetJets owner, paying standard rates, and they use Berkshire-owned aircraft for business purposes only.

Factors considered by Mr. Buffett in setting the compensation for Mr. Abel, Mr. Jain and Mr. Hamburg are typically subjective, such as his perception of each of their performance and any changes in functional responsibility. Prior to the appointments of Mr. Abel and Mr. Jain as Berkshire Vice Chairmen in 2018, Mr. Buffett set the compensation for each of the CEOs of Berkshire's significant operating businesses. However, since 2018, it has been the responsibility of Mr. Jain to set the compensation for the CEOs of Berkshire's insurance businesses and the responsibility of Mr. Abel to set the compensation for the CEOs of Berkshire's other businesses. Mr. Jain and Mr. Abel use the same general criteria as had been used by Mr. Buffett. Many different incentive arrangements are utilized, with their terms dependent on such elements as the economic potential or capital intensity of the business. The incentives can be large and are always tied to the operating results for which the CEO has authority and are related to measures over which the CEO has control.

The following table discloses the compensation received for the three years ended December 31, 2021 by the Corporation's Chief Executive Officer, its other executive officers and its Chief Financial Officer.

SUMMARY COMPENSATION TABLE

Name and Principal Position	Year	Annual Compensation		All Other Compensation	Total Compensation
		Salary	Bonus		
Warren E. Buffett	2021	$ 100,000	$ —	$273,204 (1)	$ 373,204
Chief Executive Officer/	2020	100,000	—	280,328 (1)	380,328
Chairman	2019	100,000	—	274,773 (1)	374,773
Charles T. Munger	2021	100,000	—	—	100,000
Vice Chairman of the Board	2020	100,000	—	—	100,000
	2019	100,000	—	—	100,000
Gregory E. Abel	2021	16,000,000	3,000,000 (2)	14,500 (3)	19,014,500
Vice Chairman-Non Insurance Operations	2020	16,000,000	3,000,000 (2)	14,250 (3)	19,014,250
	2019	16,000,000	3,000,000 (2)	14,000 (3)	19,014,000
Ajit Jain	2021	16,000,000	3,000,000 (2)	14,500 (3)	19,014,500
Vice Chairman-Insurance Operations	2020	16,000,000	3,000,000 (2)	14,250 (3)	19,014,250
	2019	16,000,000	3,000,000 (2)	14,000 (3)	19,014,000
Marc D. Hamburg	2021	3,312,500	—	14,500 (3)	3,327,000
Senior Vice President/CFO	2020	3,250,000	—	14,250 (3)	3,264,250
	2019	3,062,500	—	14,000 (3)	3,076,500

(1) *Represents the costs of personal and home security services provided for Mr. Buffett and paid by Berkshire. The costs of personal and home security are being reported as all other compensation as required by SEC Release No. 33872A.*

(2) *Discretionary bonus authorized by Mr. Buffett.*

(3) *Represents contributions to subsidiary defined contribution plans.*

Governance, Compensation and Nominating Committee Report

We have reviewed and discussed with management the Compensation Discussion and Analysis to be included in the Company's 2022 Shareholder Meeting Schedule 14A Proxy Statement, filed pursuant to Section 14(a) of the Securities Exchange Act of 1934 (the "Proxy"). Based on the review and discussion referred to on page 7, we recommend that the Compensation Discussion and Analysis be included in the Company's Proxy.

Submitted by the members of the Governance, Compensation and Nominating Committee of the Board of Directors.

Charlotte Guyman, Chairman
Stephen B. Burke
Kenneth I. Chenault
David S. Gottesman

CEO Pay Ratio

As mandated by Section 953(b) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and required under Item 402(u) of Regulation S-K ("Item 402(u)"), we are disclosing the median of the annual total compensation of all employees of Berkshire and its subsidiaries other than Berkshire's CEO and the annual total compensation of Berkshire's CEO, Warren E. Buffett. In preparing this disclosure, Berkshire considered the fact that on September 21, 2017, the Securities & Exchange Commission ("SEC") issued interpretive guidance to assist registrants in complying with the SEC's Pay Ratio reporting requirements. Among other things, the SEC's guidance addressed the use of reasonable estimates, assumptions and methodologies.

Berkshire also considered that Mr. Buffett's annual compensation has been $100,000 for more than the past 25 years and that Mr. Buffett receives no bonus or any form of equity-based compensation. Additionally, Berkshire has over 60 separate operating groups, many of whom have multiple separate operating groups. Accordingly, the identification of the median employee's annual total compensation of the 372,000 Berkshire subsidiary employees is a significant task.

In light of the fact that Mr. Buffett's total compensation is far less than almost all public company CEOs, Berkshire believed that the cost/benefit of complying precisely with the requirements of Item 402(u) would provide little, if any, useful information to its shareholders. Therefore, Berkshire used a judgmental sample representing approximately 2/3 of the total employees of Berkshire and its subsidiaries to determine the median employee's compensation.

The median employee was determined as of December 31, 2020 using 2020 W-2 wages for all U.S. employees and equivalent taxable compensation for all non-U.S. employees included in the sample. The median employee determination included all employees within the sample group who were employed at December 31, 2020. The annual total compensation for the median employee was calculated using the same methodology for calculating the total compensation in accordance with Item 402(c)(2)(x) of Regulation S-K.

Instruction 2 to Item 402(u) of Regulation S-K states that a registrant is required to identify its median employee once every three years provided that during the last completed year there has been no change in a registrant's employee population or employee compensation arrangements that the registrant reasonably believes would result in a significant change to its pay ratio disclosure. Berkshire does not believe that there have been any changes in its employee population or employee compensation arrangements that would result in a significant change in its pay ratio disclosure.

Accordingly, Berkshire intended to use the same employee identified in 2020 for its 2021 pay ratio calculation. However, during 2020 that employee received a promotion. Berkshire reasonably believes that continuing to use the 2020 median employee would result in a significant change in the pay ratio disclosure. Therefore, as permitted by Instruction 2 to Item 402(u) of Regulation S-K, Berkshire is using another employee whose compensation was substantially similar to that of the original median employee.

Based on the information obtained as described in the preceding paragraphs, the ratio of Mr. Buffett's annual total compensation ($373,204) to the annual total compensation of the median employee in 2021 ($58,881) was 6.34 to 1.

Delinquent Section 16(a) Reports

Section 16(a) of the Securities Exchange Act of 1934 requires the Corporation's officers and directors, and persons who own more than 10% of a registered class of the Corporation's equity securities, to file reports of ownership and changes in ownership with the Securities and Exchange Commission and the New York Stock Exchange. Officers, directors and greater than ten-percent shareholders are required by the regulations of the Securities and Exchange Commission to furnish the Corporation with copies of all Section 16(a) forms they file. Based solely on its review of the copies of such forms received by the Corporation, and written representations from certain reporting persons that no Section 16(a) forms were required for those persons, the Corporation believes that during 2021 all filing requirements applicable to its officers, directors and greater than ten-percent shareholders were complied with.

Independent Public Accountants

Deloitte & Touche LLP ("Deloitte") served as the Corporation's principal independent public accountants for 2021. Representatives from that firm will be present at the Annual Meeting of Shareholders, will be given the opportunity to make a statement if they so desire and will be available to respond to any appropriate questions. The Corporation has not selected independent public accountants for the current year, since its normal practice is for the Audit Committee of the Board of Directors to make such selection later in the year. The following table shows the fees paid or accrued for audit services and fees paid for audit-related, tax and all other services rendered by Deloitte for each of the last two years (in millions):

	2021	2020
Audit Fees *(a)*	$47.3	$47.1
Audit-Related Fees *(b)*	1.4	1.3
Tax Fees *(c)*	0.3	0.3
Other	0.1	0.1
	$49.1	$48.8

(a) Audit fees include fees for the audit of the Corporation's consolidated financial statements and interim reviews of the Corporation's quarterly financial statements, audit services provided in connection with required statutory audits of many of the Corporation's insurance subsidiaries and certain of its non-insurance subsidiaries and comfort letters, consents and other services related to Securities and Exchange Commission matters.

(b) Audit-related fees primarily include fees for certain audits of subsidiaries not required for purposes of Deloitte's audit of the Corporation's consolidated financial statements or for any other statutory or regulatory requirements, audits of certain subsidiary employee benefit plans and consultations on various accounting and reporting matters.

(c) 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 Company by Deloitte impaired the independence of Deloitte and concluded that they did not.

All of the services performed by Deloitte were pre-approved in accordance with the pre-approval policy adopted by the Audit Committee on May 5, 2003. The policy provides guidelines for audit, audit-related, tax and other non-audit services that may be provided by Deloitte to the Company. The policy (a) identifies the guiding principles that must be considered by the Audit Committee in approving services to ensure that Deloitte's 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 Company's independent auditor and its 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 the Company's Chief Financial Officer and must include a detailed description of the services to be rendered. The 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.

Report of the Audit Committee

February 23, 2022

To the Board of Directors of Berkshire Hathaway Inc.

We have reviewed and discussed the consolidated financial statements of the Corporation and its subsidiaries to be set forth in Item 8 of the Corporation's Annual Report on Form 10-K for the year ended December 31, 2021 with management of the Corporation and Deloitte & Touche LLP, independent public accountants for the Corporation.

We have also discussed with Deloitte & Touche LLP the matters required by the Public Company Accounting Oversight Board ("PCAOB") to be discussed, as adopted in Auditing Standard No. 16 (Communications with Audit Committees). We have received the written disclosures and the letter from Deloitte & Touche LLP required by the applicable PCAOB requirements for independent accountant communications with audit committees with respect to auditor independence and have discussed with Deloitte & Touche LLP its independence from the Corporation.

It is not the duty of the Audit Committee to plan or conduct audits or to determine that the Corporation's financial statements are complete and accurate and in accordance with generally accepted accounting principles; that is the responsibility of management and the Corporation's independent public accountants. In giving its recommendation to the Board of Directors, the Audit Committee has relied on (i) management's representation that such financial statements have been prepared with integrity and objectivity and in conformity with generally accepted accounting principles and (ii) the reports of the Corporation's independent public accountants with respect to such financial statements.

Based on the review and discussions with management of the Corporation and Deloitte & Touche LLP referred to above, we recommend to the Board of Directors that the Corporation publish the consolidated financial statements of the Corporation and subsidiaries for the year ended December 31, 2021 in the Corporation's Annual Report on Form 10-K.

Submitted by the members of the Audit Committee of the Board of Directors.

Susan L. Decker, Chairperson
Christopher C. Davis
Meryl B. Witmer

Communications with the Board of Directors

Shareholders and other interested parties who wish to communicate with the Board of Directors or a particular director may send a letter to the Secretary of the Corporation at 3555 Farnam Street, Omaha, NE 68131. The mailing envelope must contain a clear notation indicating that the enclosed letter is a "Board Communication" or "Director Communication." All such letters must clearly state whether the intended recipients are all members of the Board or just certain specified individual directors. The Secretary will make copies of all such letters and circulate them to the appropriate director or directors.

Security Ownership of Certain Beneficial Owners

Warren E. Buffett, whose address is 3555 Farnam Street, Omaha, NE 68131, is a nominee for director and the beneficial owner of more than 5% of the Corporation's Class A Stock. FMR LLC, whose address is 245 Summer Street, Boston, MA 02210, reported on a Form 13-G filed with the Securities and Exchange Commission ("SEC") on February 9, 2022 it was the beneficial owner of 31,998 shares of Class A Stock. Such shares represent approximately 5.2% of the outstanding shares of Class A Stock. Blackrock Inc. whose address is 55 East 52nd Street, New York, NY 10055, reported on a Form 13-G filed with the SEC on February 3, 2022 it was the beneficial owner of 101,111,126 shares of Class B Stock. Such shares represent approximately 7.8% of the outstanding shares of Class B Stock. The Vanguard Group, whose address is 100 Vanguard Boulevard, Malvern, PA 19355, reported on a Form 13-G filed with the SEC on February 9, 2022 it was the beneficial owner of 131,774,278 shares of Class B Stock. Such shares represent 10.2% of the outstanding shares of Class B Stock. State Street Corporation, whose address is 1 Lincoln Street, Boston, MA 02111, reported on a Form 13-G filed with the SEC on February 14, 2022 it was the beneficial owner of 77,706,600 shares of Class B Stock. Such shares represent 6.0% of the outstanding shares of Class B Stock.

Security Ownership of Directors and Executive Officers

Beneficial ownership of the Corporation's Class A and Class B Stock on March 2, 2022 by the executive officers and directors of the Corporation and Mr. Weitz is shown in the following table:

Name	Title of Class of Stock	Shares Beneficially Owned (1)	Percentage of Outstanding Stock of Respective Class (1)	Percentage of Aggregate Voting Power of Class A and Class B (1)	Percentage of Aggregate Economic Interest of Class A and Class B (1)
Warren E. Buffett	Class A	238,624	38.8		
	Class B	2,412	*	32.1 (2)	16.2
Gregory E. Abel	Class A	5 (3)	*		
	Class B	2,363 (3)	*	*	*
Howard G. Buffett	Class A	660 (4)	0.1		
	Class B	2,450	*	0.1	*
Susan A. Buffett	Class A	81 (5)	*		
	Class B	3,092,162 (5)	0.2	0.1	0.1
Stephen B. Burke	Class A	28	*		
	Class B	—	*	*	*
Kenneth I. Chenault	Class A	3	*		
	Class B	1,855	*	*	*
Christopher C. Davis	Class A	36	*		
	Class B	2,666	*	*	*
Susan L. Decker	Class A	—	*		
	Class B	3,125	*	*	*
David S. Gottesman	Class A	21,654 (6)	3.5		
	Class B	2,166,006 (6)	0.2	2.9	1.6
Charlotte Guyman	Class A	60	*		
	Class B	—	*	*	*
Ajit Jain	Class A	316 (7)	0.1		
	Class B	170,958 (7)	*	*	*
Charles T. Munger	Class A	4,270	0.7		
	Class B	643	*	0.6	0.3
Ronald L. Olson	Class A	145 (8)	*		
	Class B	25,332 (8)	*	*	*
Wallace R. Weitz	Class A	174 (9)	*		
	Class B	—	*	*	*
Meryl B. Witmer	Class A	11 (10)	*		
	Class B	2,000	*	*	*
Directors and executive officers as a group	Class A	266,067	43.3		
	Class B	5,471,972	0.4	35.8	18.3

* less than 0.1%

(1) *Beneficial owners exercise both sole voting and sole investment power unless otherwise stated. Each share of Class A Stock is convertible into 1,500 shares of Class B Stock. Pursuant to Rule 13d-3(d)(1) of the Securities Exchange Act of 1934, a shareholder is deemed to have beneficial ownership of the shares of Class B Stock which such shareholder may acquire upon conversion of the Class A Stock. In order to avoid overstatement, the amount of Class B Stock beneficially owned does not take into account shares of Class B Stock which may be acquired upon conversion.*

(2) *Mr. Buffett has entered into a voting agreement with Berkshire providing that, should the combined voting power of Berkshire shares as to which Mr. Buffett has or shares voting and investment power exceed 49.9% of Berkshire's total voting power, he will vote those shares in excess of that percentage proportionately with votes of the other Berkshire shareholders.*

(3) *Includes 5 Class A shares held by a trust for which Mr. Abel is a trustee but with respect to which he disclaims any beneficial interest and 2,363 Class B shares held by Mr. Abel as custodian for members of his family but with respect to which he disclaims any beneficial interest.*

(4) *Includes 650 Class A shares held by a private foundation for which Mr. Buffett possesses voting and investment power but with respect to which he disclaims any beneficial interest.*

(5) *Includes 56 Class A shares and 3,091,712 Class B shares held by a private foundation for which Ms. Buffett possesses voting power but with respect she disclaims any beneficial interest.*

(6) *Includes 14,279 Class A shares and 2,159,250 Class B shares as to which Mr. Gottesman has shared voting power and 3,928 Class A shares and 2,010,806 Class B shares as to which Mr. Gottesman has shared investment power. Mr. Gottesman has a pecuniary interest in 6,402 Class A shares and 395 Class B shares included herein.*

(7) *Includes 302 Class A shares owned by Trusts for the benefit of Mr. Jain's children and grandchildren. Also includes 170,043 Class B shares owned by a private foundation for which Mr. Jain possesses voting and investment power but with respect to which he disclaims any beneficial interest.*

(8) *Includes 29 Class A shares and 1,297 Class B shares held by a trust for which Mr. Olson is a trustee but with respect to which Mr. Olson disclaims any beneficial interest.*

(9) *Includes 154 Class A shares held by a private foundation for which Mr. Weitz possesses voting and investment power but with respect to which he disclaims any beneficial interest.*

(10) *Includes 4 shares in which Ms. Witmer is a trustee but with respect to which she disclaims any beneficial interest. Does not include 4 Class A shares owned by Ms. Witmer's husband.*

2. SHAREHOLDER PROPOSAL

National Legal and Policy Center, owner of shares of Berkshire Common Stock with a value in excess of $2,000, has given notice that a representative from National Legal and Policy Center intends to present for action at the meeting the following proposal.

Resolved: Shareholders request the Board of Directors adopt as policy, and amend the bylaws as necessary, to require hereafter that the Chair of the Board of Directors be an independent member of the Board, consistent with applicable law and existing contracts. If the Board determines that a Chair who was independent when selected is no longer independent, the Board shall select a new Chair who satisfies the requirements of the policy within a reasonable amount of time.

Supporting Statement

Berkshire Hathaway Inc.'s Chief Executive Officer is also Board Chairman. We believe these roles – each with separate, different responsibilities that are critical to the health of a successful corporation – are greatly diminished when held by a singular company official, thus weakening its governance structure.

Expert perspectives substantiate our position:

- According to the Council of Institutional Investors (https://bit.ly/3pKrtJK), "A CEO who also serves as chair can exert excessive influence on the board and its agenda, weakening the board's oversight of management. Separating the chair and CEO positions reduces this conflict, and an independent chair provides the clearest separation of power between the CEO and the rest of the board."
- A 2014 report from Deloitte (https://bit.ly/3vQGqe1) concluded, "The chairman should lead the board and there should be a clear division of responsibilities between the chairman and the chief executive officer (CEO)."
- Proxy adviser Glass Lewis advised (https://bit.ly/2ZD4159) in 2016, "an independent chairman…is better able to oversee the executives of the Company and set a pro-shareholder agenda without the management conflicts that exist when a CEO or other executive also serves as chairman."

THE BOARD OF DIRECTORS UNANIMOUSLY FAVORS A VOTE AGAINST THE PROPOSAL FOR THE FOLLOWING REASONS:

Warren Buffett, Berkshire's CEO, currently has a 32% voting interest in Berkshire. The Board believes that as long as Mr. Buffett is Berkshire's CEO, he should continue as Board Chair and as Berkshire's CEO. However, as has been stated on numerous occasions by Mr. Buffett in the past, once Mr. Buffett is no longer Berkshire's CEO, a non-management director should be named Board Chair. The Board agrees with Mr. Buffett and accordingly recommends that the shareholders vote against this proposal.

Proxies given without instruction will be voted AGAINST this shareholder proposal.

3. SHAREHOLDER PROPOSAL

Brunel Pension Partnership Limited ("Brunel")[1], represented by EOS at Federated Hermes ("EOS"), Caisse de Dépôt et Placement du Québec, California Public Employees' Retirement System and State of New Jersey Common Pension Fund D each own shares of Berkshire Common Stock with a value in excess of $2,000. These co-sponsors have given notice that a representative from EOS intends to present for action at the meeting the following proposal.

Resolved: In the interest of the long-term success of Berkshire Hathaway Inc. (the "Company") and so investors can manage risk more effectively, shareowners request the board of the Company publish an annual assessment addressing how the Company manages physical and transitional climate-related risks and opportunities, commencing prior to its 2023 annual shareholder's meeting. Shareowners recommend the assessment address:

1. Summaries of risks and opportunities at the parent Company level and for only those Company subsidiaries and investee organizations that the board believes could be materially impacted by climate change, disclosed in accordance with the Taskforce on Climate-related Financial Disclosure (TCFD) recommendations,
2. The board's oversight of climate related risks and opportunities, and
3. The feasibility of establishing company-wide science-based, greenhouse gas (GHG) reduction targets.

The Assessment may be a stand-alone report or incorporated into existing reporting, be prepared at a reasonable cost, and omit proprietary information.

Supporting Statement

Climate change and the transition to a low-carbon economy pose critical risks to investors. All companies should appraise and disclose physical and transitional climate risks. The Company's current disclosures are insufficient for investors to fully appraise climate-related risks and opportunities.

1 EOS is acting pursuant to delegated authority on behalf of Brunel. EOS' views and positions are those of EOS, and do not necessarily represent the views or positions of all its clients or Federated Hermes, Inc. or its other subsidiaries.

At the 2021 annual meeting, where a significant majority of non-insider shareholders supported a similar version of this resolution, the Company stated that climate disclosure at the parent Company level is unnecessary given the Company's selective and partial subsidiary climate disclosures. However, shareholders can purchase shares only in the combined parent-company entity, not in the individual subsidiaries that may or may not have climate risk exposure. A parent Company climate risk disclosure to investors does not exist, is needed, and entails a modest degree of reporting centralization. Over 2,600 companies globally support the TCFD recommendations, with 98 of the Climate Action 100+ companies already reporting in line with this framework. Over 1,000 corporations have joined the Science Based Targets Initiative (SBTi) to set verifiable GHG reduction targets consistent with limiting global emissions to well-below 2°C. We welcome railroad subsidiary BNSF's SBTi commitment.

Also, the Securities and Exchange Commission has said climate-related disclosures may yield information material to investors and companies navigating the low carbon transition and may become mandatory in the near term.

THE BOARD OF DIRECTORS UNANIMOUSLY FAVORS A VOTE AGAINST THE PROPOSAL FOR THE FOLLOWING REASONS:

The proponents' assertion that at the 2021 Annual Meeting, a significant majority of non-insider shareholders supported a similar resolution is incorrect. In fact, a significant majority of such shareholders did not support the proposal.

The Board of Directors does not believe that an annual assessment with summaries of risks and opportunities at the parent Company level disclosed in accordance with the recommendations of the Task Force on Climate-Related Financial Disclosures is necessary. As further discussed below, the Board believes the vast majority of Berkshire's greenhouse gas emissions footprint and the risks associated with and opportunities created by climate change are appropriately managed and reported publicly by individual businesses.

The Board believes that climate risk, enterprise risk and shareholder risk should be considered simultaneously and in context. In assessing the individual and collective greenhouse gas emissions footprint of the Berkshire operating companies, it is also important to consider each company's contributions to net income. Companies with a small greenhouse gas footprint and a small contribution to net income are unlikely to present significant risk in the overall transition to a low-carbon economy. Berkshire Hathaway Energy ("BHE") and BNSF are the two most carbon-intensive Berkshire businesses, representing the vast majority of Berkshire's Scope 1 and Scope 2 greenhouse gas emissions.

BHE is striving to achieve net zero greenhouse gas emissions by 2050 in a manner its customers can afford, its regulators will allow and technology advances support. As part of that journey, it expects to achieve a 50% reduction in its Scope 1 and Scope 2 greenhouse gas emissions by 2030 from 2005 levels. BHE has laid out a roadmap to achieve these emissions reductions in numerous publicly available reports, investor presentations and individual investor communications. BNSF has committed to setting greenhouse gas emissions reduction targets as part of the Science Based Targets initiative in 2022. For BNSF, greenhouse gas emissions associated with its locomotive fuel are added to its Scope 1 and Scope 2 greenhouse gas emissions to develop its working target, which reflects a 30% reduction by 2030 from 2018 levels. Certain other Berkshire companies have also evaluated climate-related risks and opportunities and have determined it is advantageous to publicly commit to reducing their emissions.

Because many of Berkshire's subsidiaries are already making and reporting on their climate-related decisions, the Board recommends that our shareholders vote against this proposal.

Proxies given without instruction will be voted AGAINST this shareholder proposal.

4. SHAREHOLDER PROPOSAL

Gail Follansbee on behalf of Myra K. Young, owner of shares of Berkshire Common Stock with a value in excess of $2,000, intends to present for action at the meeting the following proposal.

Whereas: Insurance companies have a critical role to play in meeting the Paris Agreement's 1.5 degrees Celsius ("1.5°C") goal, requiring net zero greenhouse gas (GHG) emissions by 2050. Projections[1] have found that limiting global warming to 1.5 degrees versus 2 degrees will save $20 trillion globally by 2100; while exceeding 2 degrees could lead to climate damages in the hundreds of trillions.[2] The U.S. insurance industry is under increasing pressure to address its contributions to climate change from underwriting, insuring, and investing in high emitting activities.[3]

These financial activities contribute to systemic portfolio risk to the global economy, investors, and insurers' profitability. The U.S. Commodity Futures Trading Commission recently acknowledged that climate change could impair the productive capacity of the national economy and recommended that state insurance regulators require insurers to assess how their underwriting activity and investment portfolios may be impacted by climate-related risks.

1 https://www.nature.com/articles/d41586-018-05219-5
2 https://www.nature.com/articles/s41467-020-18797-8/
3 https://shareaction.org/reports/insuring-disaster-a-ranking

This growing public pressure for the insurance industry to account for its climate related risks is exemplified by legislation recently passed in Connecticut[4] requiring regulators to incorporate emissions reduction targets into their supervision of insurers.

Shareholders are concerned that Berkshire Hathaway is not adequately reducing the climate footprint of its insurance operations — which make up over 26% of its business and is its largest value segment.[5] This failure creates significant risk. Berkshire's combined insurance units posted a $784 million pre-tax underwriting loss[6] largely attributable to $1.7 billion in catastrophe claims, including claims from Hurricane Ida and flooding in Europe. This follows a larger global trend: insured losses from natural disasters reached $42 billion in the first six months of 2021, a ten year high.[7]

Berkshire is a climate laggard in the global insurance sector, scoring in the bottom in a survey of the 30 largest global insurers[8], due largely to its lack of restrictions on fossil fuel underwriting and investments. In contrast, peers are beginning to address the GHG emissions associated with their underwriting and investment activities. Thirteen global insurers have also joined the United Nations' Net Zero Insurance Alliance in which they commit to transition their emissions from insurance and reinsurance underwriting portfolios to net zero by 2050.

Berkshire does not measure or disclose its financed emissions, including those attributable to underwriting and insuring, nor has it adopted targets aligned with the Paris Agreement's 1.5°C goal.

Be It Resolved: Shareholders request that Berkshire issue a report, at reasonable cost and omitting proprietary information, addressing if and how it intends to measure, disclose, and reduce the GHG emissions associated with its underwriting, insuring, and investment activities, in alignment with the Paris Agreement's 1.5°C goal, requiring net zero emissions.

Supporting Statement

Shareholders recommend the report disclose at board discretion:

- Whether Berkshire will begin measuring and disclosing the emissions associated with the full range of its operations and by when, and
- Whether Berkshire will set a Paris aligned, net zero target, and on what timeline

4 https://www.businessinsurance.com/article/20210617/NEWS06/912342605/Connecticut-bill-calls-for-regulation-of-insurers%E2%80%99-climate-risks
5 https://www.spglobal.com/esg/insights/completing-data-gaps-in-environmental-performance-disclosure
6 https://www.insurancejournal.com/news/national/2021/11/08/641046.htm
7 https://www.weforum.org/agenda/2021/07/natural-disasters-cost-economic-insurance-2021-extreme-weather-floods-polar-vortex/
8 https://insure-our-future.com/scorecard

THE BOARD OF DIRECTORS UNANIMOUSLY FAVORS A VOTE AGAINST THE PROPOSAL FOR THE FOLLOWING REASONS:

Berkshire's Board recommends a "no" vote on this proposal. The Board does not believe issuing a report addressing if and how Berkshire intends to measure, disclose and reduce the greenhouse gas emissions associated with its underwriting, insuring and investment activities is necessary.

The primary business of Berkshire's insurance operations is to monitor, assess and price risk at an expected economic profit to address the risk-transfer needs of its insurance customers. The insurance risks associated with climate change are assessed within the enterprise risk management framework, along with the adoption of climate-specific risk management procedures. These procedures include stress testing and review of post-stress metrics as well as consideration of the frequency and severity of weather events and regulatory adjustments that may impact underwriting decisions or adversely impact future operating results.

Berkshire's Board periodically receive reports on the major risks and opportunities of Berkshire's operating businesses. The insurance operations' continual assessment of the risk of natural disasters, strong underwriting controls to limit exposure and stress testing lead the Board to conclude that climate-related risks within the insurance group are appropriately monitored and managed within the Board's risk appetite. Accordingly, the Board recommends that our shareholders vote against this proposal.

Proxies given without instruction will be voted AGAINST this shareholder proposal.

5. SHAREHOLDER PROPOSAL

As You Sow on behalf of Warren Wilson College and The Elizabeth Kantor Trust U/A DTD 3/11/1993 each the owner of shares of Berkshire Common Stock with a value in excess of $2,000 intends to present for action at the meeting the following proposal.

Whereas: "In neither the purchase of goods nor the hiring of personnel, do we ever consider the religious views, the gender, the race or the sexual orientation of the persons we are dealing with. It would not only be wrong to do so, it would be idiotic. We need all of the talent we can find, and we have learned that able and trustworthy managers, employees and suppliers come from a very wide spectrum of humanity." — Warren E. Buffett, February 28, 2002[1]

Companies should look to hire the best talent. However, Black and Latino applicants face recruitment challenges. Results of a meta-analysis study of 24 field experiments, dating back to 1990, found that, with identical resumes, White applicants receive, an average of 36 percent more callbacks than Black applicants and 24 percent more callbacks than Latino applicants."[2]

Promotion rates show how well diverse talent is nurtured at a company. Unfortunately, women and non-White employees experience "a broken rung" in their careers. For every 100 men who are promoted, only 86 women are promoted. Non-White women are particularly impacted, comprising 17 percent of the entry-level workforce and only 4 percent of executives.[3]

Morgan Stanley has found that: "Employee retention that is above industry peer averages can indicate the presence of competitive advantage. This advantage may lead to higher levels of future profitability than past financial performance would indicate."[4] Companies with high employee satisfaction have also been linked to annualized outperformance of over two percent.[5]

Berkshire Hathaway Inc. ("Berkshire Hathaway") has not yet committed to release standardized workforce composition data, at any level of its businesses. Nor has it released sufficient recruitment, retention, and promotion data to allow investors to determine the effectiveness of Berkshire Hathaway's companies' human capital management programs.

Eighty-one percent of the S&P100 have released, or have committed to release, their EEO-1 forms, best practice in workforce composition reporting. The number of S&P100 companies releasing this form increased 239 percent between September 2020 and September 2021. The number of S&P100 companies releasing recruitment rate data by gender, race, and ethnicity increased by 234 percent; companies releasing retention rate data increased by 79 percent, and companies releasing promotion rate data increased by 379 percent. Berkshire Hathaway is an outlier in its decision to withhold these data sets.

Resolved: Shareholders request that Berkshire Hathaway or its holding companies report to shareholders on the outcomes of their diversity, equity, and inclusion efforts by publishing quantitative data on workforce composition, and recruitment, retention, and promotion rates of employees by gender, race, and ethnicity. The reporting should be done at reasonable expense and exclude proprietary information.

Supporting Statement

Quantitative data is sought so investors can assess, understand, and compare the effectiveness of companies' diversity, equity, and inclusion programs and apply this analysis to investors' portfolio management and securities' selection process.

---

1 https://www.berkshirehathaway.com/letters/2001pdf.pdf
2 https://hbr.org/2017/10/hiring-discrimination-against-black-americans-hasnt-declined-in-25-years
3 https://wiw-report.s3.amazonaws.com/Women_in_the_Workplace_2021.pdf
4 https://www.morganstanley.com/im/publication/insights/articles/article_culturequantframework_us.pdf
5 https://www.institutionalinvestor.com/article/b1tx0zzdhhnf5x/Want-to-Pick-the-Best-Stocks-Pick-the-Happiest-Companies?utm_medium=email&utm_campaign=The%20Essential%2011%20100721&utm_content=The%20Essential%2011%20100721%20CID_eb103a9e15359075f72a85f7ff534c79&utm_source=CampaignMonitorEmail&utm_term=Want%20to%20Pick%20the%20Best%20Stocks%20Pick%20the%20Happiest%20Companies

THE BOARD OF DIRECTORS UNANIMOUSLY FAVORS A VOTE AGAINST THE PROPOSAL FOR THE FOLLOWING REASONS:

Berkshire's commitment to diversity, equity and inclusion and the effectiveness of our companies' related programs starts with our leaders, including our Board of Directors, of which four members are female and two members are racially or ethnically diverse. To ensure long-term success for our shareholders, Berkshire encourages its leaders to execute diversity, equity and inclusion strategies that are tailored to the unique aspects of their business.

Berkshire's operating companies continue to show their commitment to diversity, equity and inclusion through a number of actions, including, at certain companies, the creation of senior level positions and/or employee-driven committees to support these efforts at their respective organizations. These actions ensure the culture and practices of our companies reflect a workplace that welcomes and values all.

Berkshire manages its operating businesses on an unusually decentralized basis and has minimal involvement in these businesses' day-to-day activities. Accordingly, Berkshire's Board recommends that our shareholders vote against this proposal, supporting the long-standing business model that each business is individually responsible for developing and implementing policies, programs and results, including those related to diversity, equity and inclusion.

Proxies given without instruction will be voted AGAINST this shareholder proposal.

6. OTHER MATTERS

As of the date of this statement your management knows of no business to be presented to the meeting that is not referred to in the accompanying notice other than the approval of the minutes of the last Annual Meeting of Shareholders, which action will not be construed as approval or disapproval of any of the matters referred to in such minutes. As to other business that may properly come before the meeting, it is intended that proxies properly executed and returned will be voted in respect thereof at the discretion of the person voting the proxies in accordance with his or her best judgment, including upon any shareholder proposal about which the Corporation did not receive timely notice.

Annual Report

The Annual Report to the Shareholders for 2021 accompanies this proxy statement, but is not deemed a part of the proxy soliciting material.

A copy of the 2021 Form 10-K report as filed with the Securities and Exchange Commission, excluding exhibits, will be mailed to shareholders without charge upon written request to: Corporate Secretary, Berkshire Hathaway Inc., 3555 Farnam Street, Omaha, NE 68131. Such request must set forth a good-faith representation that the requesting party was either a holder of record or a beneficial owner of Class A or Class B Stock of the Corporation on March 2, 2022. Exhibits to the Form 10-K will be mailed upon similar request and payment of specified fees. The 2021 Form 10-K is also available through the Securities and Exchange Commission's website (www.sec.gov).

Proposals of Shareholders

Any shareholder proposal intended to be considered for inclusion in the proxy statement for presentation at the 2023 Annual Meeting must be received by the Corporation by November 15, 2022. The proposal must be in accordance with the provisions of Rule 14a-8 promulgated by the Securities and Exchange Commission under the Securities Exchange Act of 1934. It is suggested the proposal be submitted by certified mail – return receipt requested. Shareholders who intend to present a proposal at the 2023 Annual Meeting without including such proposal in the Corporation's proxy statement must provide the Corporation notice of such proposal no later than January 31, 2023. The Corporation reserves the right to reject, rule out of order or take other appropriate action with respect to any proposal that does not comply with these and other applicable requirements.

By order of the Board of Directors

MARC D. HAMBURG, *Secretary*

Omaha, Nebraska
March 11, 2022

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

In the Matter of the Application of PACIFICORP (U-901-E), for an Order Authorizing a General Rate Increase Effective January 1, 2023.	Application No. 22-05-____ (Filed May 5, 2022)

PACIFICORP (U-901-E)
NOTICE OF AVAILABILITY
OF PACIFICORP'S (U-901-E) APPLICATION FOR AN ORDER AUTHORIZING A GENERAL RATE INCREASE EFFECTIVE JANUARY 1, 2023

On May 5, 2022, PacifiCorp (U-901-E) filed an Application for an Order Authorizing a General Rate Increase Effective January 1, 2023 (Application). PacifiCorp proposes an overall increase in its base electric rates of approximately $27.9 million, or a 25.7 percent net increase to California retail customers. PacifiCorp has also prepared direct testimony and exhibits in support of its Application.

Consistent with Rule 1.9 of the Rules of Practice and Procedure of the California Public Utilities Commission, PacifiCorp is issuing this Notice of Availability. The filing exceeds 50 pages in length and 3.5 megabytes in size, electronically. This Notice of Availability is being served on appropriate parties under Cal. Code Reg. 20 § 3.2(b). PacifiCorp's Application, testimony, and exhibits may be viewed and downloaded at the following URL: https://www.pacificpower.net/about/rates-regulation/california-regulatory-filings.html.

The exhibits are available at this URL as of today.

Respectfully submitted May 5, 2022, at Portland, Oregon.

By: Carla Scarsella
Carla Scarsella

Carla Scarsella
Deputy General Counsel
PacifiCorp
825 NE Multnomah Street, Suite 2000
Portland, Oregon 97232
Phone: 503-813-6338
Email: carla.scarsella@pacificorp.com

Attorney for PacifiCorp