**BEFORE THE PUBLIC UTILITIES COMMISSION**

**OF THE STATE OF CALIFORNIA**

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|---|---|
| In the Matter of the Application of PacifiCorp (U 901 E) for Approval of its 2022 Energy Cost Adjustment Clause and Greenhouse Gas-Related Forecast and Reconciliation of Costs and Revenue | Application No. 21-08-___ (Filed August 2, 2021) |

# APPLICATION OF PACIFICORP (U 901 E) FOR APPROVAL OF ITS 2022 ENERGY COST ADJUSTMENT CLAUSE AND GREENHOUSE GAS-RELATED FORECAST AND RECONCILIATION OF COSTS AND REVENUE

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Date: August 2, 2021

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| In the Matter of the Application of PacifiCorp (U 901 E) for Approval of its 2022 Energy Cost Adjustment Clause and Greenhouse Gas-Related Forecast and Reconciliation of Costs and Revenue | Application No. 21-08-___ (Filed August 2, 2021) |

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## I. INTRODUCTION

In accordance with Rules 2.1 and 3.2,[1] PacifiCorp d/b/a Pacific Power (PacifiCorp or Company) respectfully submits this application requesting approval to decrease both the Balancing Rate and the Offset Rate under its Energy Cost Adjustment Clause (ECAC) that are currently in effect, which were approved in Decision (D.) 20-12-004.[2,3] Consistent with D.12-12-033, D.13-12-041, and D.14-10-033 issued by the California Public Utilities Commission (Commission), PacifiCorp also requests to update both the surcharge that recovers the costs for the procurement of greenhouse gas (GHG) allowances for its retail compliance obligation under California's Cap and Trade Program, and the California Climate Credit that returns revenue from the sale of GHG allowances to eligible customer classes. PacifiCorp also requests a waiver of certain requirements in the Commission's Decision, D.20-12-004, issued in the Company's 2020

[1] Unless otherwise specified, all citations to a rule are to the Commission's Rules of Practice and Procedure.

[2] The ECAC was initially authorized as part of PacifiCorp's 2005 general rate case. *See* D.06-12-011. The Commission authorized continued use of the ECAC as part of PacifiCorp's 2019 general rate case. *See* D.20-02-025.

[3] In D.20-12-004, the Commission approved the Offset and Balancing Rates as proposed in Application (A.) 19-08-002. The Offset and Balancing Rates proposed in the 2021 ECAC, A.20-08-002, are still pending before the Commission.

ECAC because of new modeling software used to forecast net power costs (NPC) for this filing which make the need for those requirements in the Decision obsolete.

As described in more detail below, based on rates currently in effect, PacifiCorp requests an overall rate decrease of $2.0 million or 1.9 percent for the combined effect of the proposed changes in its ECAC rates and GHG cost recovery rates. This decrease is comprised of a decrease in the ECAC Balancing Rate of approximately $2.4 million compared to current rates, a decrease in the ECAC Offset Rate of approximately $3.0 million from the amount currently in rates, and an increase of approximately $3.4 million in the GHG allowance costs to be recovered in rates.

The estimated combined effect of the proposed ECAC and GHG cost recovery rates is summarized by customer class in Table 1 below:

**Table 1: Proposed Price Changes by Customer Class**

| **Customer Class** | **Proposed Price Change** | |
|---|---|---|
| | **Dollars** | **Percent (%)** |
| Residential | -$901,000 | -1.6% |
| Commercial/Industrial | -$872,00 | -2.3% |
| Irrigation | -$270,000 | -2.0% |
| Lighting | $1,000 | 0.1% |
| Overall | -$2,042,000 | -1.9% |

The industry and small business assistance factors provided in D.13-12-002 do not extend past the year 2020. Therefore, for this filing, the Company used the small business assistance factor for 2020 provided in Appendix 2 of D.13-12-002 and continued for use in 2021 which was approved by D.20-10-022. Thus, in this application the Small Business customers would receive a California Climate Credit in 2022, which offsets 50 percent of the surcharge they will pay in 2022 for GHG cost recovery. The Company also requests from the Commission further guidance as to the proper assistance factor to be used to calculate the GHG revenue allocation for small business customers going forward.[4] The proposed semi-annual residential California Climate Credit for 2022 is $154.58.

The changes to the ECAC Balancing Rate, ECAC Offset Rate and GHG cost recovery is discussed in Section III below.

## II. BACKGROUND

### A. ECAC

On November 29, 2005, PacifiCorp filed a general rate case application, A.05-11-022, with the Commission. As part of its application, PacifiCorp requested authority to implement an ECAC to allow for timely and efficient recovery of its NPC. In D.06-12-011, the Commission approved A.05-11-022 and adopted the terms of two settlements, including PacifiCorp's proposed ECAC. As directed by the Commission, PacifiCorp filed revised tariff sheets implementing the ECAC by advice letter on December 21, 2006, which became effective January 1, 2007. The use of the ECAC mechanism was continued in D.20-02-025, which was the decision in PacifiCorp's 2019 general rate case (2019 Rate Case). The Commission has approved PacifiCorp's annual applications under the ECAC. The ECAC Application is filed annually on August 1.

### B. GHG Allowance Costs and Revenues

In 2006, the California Legislature passed Assembly Bill (AB) 32, the Global Warming Solutions Act, which required California to develop regulations that will reduce GHG emissions to 1990 levels by 2020 (Cap and Trade Program). The Cap and Trade Program, administered by the California Air Resources Board (ARB), is one element of achieving this goal. ARB

[4] See PAC/600, the direct testimony of Judith M. Ridenour. An upcoming decision in Rulemaking (R.) 20-05-002 may change how the credit is applied to Small Business customers.

encourages the reduction of GHG emissions by placing a cap on the amount of GHG emissions a facility can emit. This is regulated through the implementation of GHG emissions allowances or permits. Under California's Cap and Trade Program, starting in 2013, ARB allocated PacifiCorp and other California electric utilities GHG emissions allowances. PacifiCorp is required to sell all of its allocated GHG emissions allowances at auction and return the revenue from the sale to its eligible customers, less some revenue to cover administrative and outreach costs and fund energy efficiency programs.[5] The revenue is returned to residential customers through the California Climate Credit paid twice a year in April and October. PacifiCorp and other California electric utilities must also buy a sufficient number of GHG emissions allowances to cover their annual compliance obligation under the program. The costs for buying GHG emissions allowances to meet its retail compliance obligations are collected from all California customers and are not included in PacifiCorp's ECAC rates.

On December 20, 2012, the Commission issued D.12-12-033, which, among other things, adopted a methodology for allocating GHG allowance revenues to eligible customers and directed utilities to record GHG allowance costs and estimated GHG allowance revenues to certain balancing accounts. On October 16, 2014, the Commission issued D.14-10-033,

[5] *See* Administrative Law Judge Ruling issued March 18, 2016 in R.14-07-002, directing utilities to set aside five percent of 2016 GHG Allowance proceeds and ten percent of 2017 GHG Allowance proceeds for clean energy programs associated with the implementation of AB 693. The Ruling at page 5 further stated "The directions for ERRA and ECAC filings given in this ruling will continue to apply unless they are explicitly changed by a subsequent ruling or Commission decision." Accordingly, PacifiCorp set aside these amounts for 2016, 2017, and 2018, in its 2018 ECAC Application (A.17-08-005). D.17-12-022, issued on December 14, 2017, PacifiCorp was directed to set aside ten percent of the proceeds from the sale of greenhouse gas allowances starting with the 2018 ECAC for use in the Solar on Multifamily Affordable Housing Program. In compliance with D.17-12-022, in its 2019 (A.18-08-001), 2020 ECAC (A.19-08-002), 2021 (A.20-08-002), and 2022 ECAC, PacifiCorp set aside ten percent of the forecast GHG allowance proceeds. See Confidential Exhibit PAC/605.

directing all utilities, beginning in 2015, to file their annual GHG applications as part of their Energy Resource Recovery Account (ERRA) or ECAC application.[6]

## III. DESCRIPTION OF REQUEST

As explained in more detail below, in this application PacifiCorp is requesting authorization to update the following rates for 2022:

- ECAC Balancing Rate;
- ECAC Offset Rate;
- Carbon Pollution Permit Cost Surcharge that recovers the costs for the procurement of GHG allowances; and
- California Climate Credit that returns the revenue from the sale of GHG allowances.

### A. ECAC

PacifiCorp respectfully requests that the Commission authorize PacifiCorp to update its ECAC rates effective January 1, 2022. PacifiCorp requests a Balancing Rate of $4.25 per megawatt-hour (MWh) and an Offset Rate of $25.15 per MWh, effective January 1, 2022. As previously discussed, based on rates currently in effect (approved in D.20-12-004), the 2022 ECAC proposed change to the Balancing Rate results in a rate decrease of $2.4 million and the proposed change to the Offset Rate results in a rate decrease of $3.0 million for an overall decrease in the ECAC rates of approximately $5.4 million. Rate impacts are calculated based on present rates which do not reflect the proposed ECAC rates from the Company's pending 2021 ECAC in A.20-08-002. A comparison of the Offset and Balancing Rates approved in D.20-12-

[6] *See* D.14-10-033, page 30.

004, proposed in the pending 2021 ECAC, and proposed in this Application is reflected in Table 2 below.

**Table 2: Comparison of Balancing and Offset Rates**

| | 2020 ECAC approved in D.20-12-004 | 2021 ECAC Proposed in A.20.08-002* | 2022 ECAC Proposed in this Application |
|---|---|---|---|
| Balancing Rate | $7.50/MWh | $1.05/MWh | 4.25/MWh |
| Offset Rate | $29.21/MWH | $23.88/MWh | $25.15/MWh |
| * ECAC portion of A.20-08-002 is currently pending before the Commission | | | |

The following components are included in the ECAC:

(1) Net power costs;

(2) Fuel stock carrying charge;

(3) ARB implementation fees[7] and mandatory reporting verification costs[8] (collectively referred to in this application as ARB Administrative Costs);

(4) Net metering surplus compensation;

(5) Purchase of renewable energy credits (RECs) for renewables portfolio standard (RPS) compliance;

(6) A credit for renewable energy production tax credits (PTCs);[9] and

(7) Start-up fuels costs.[10]

[7] ARB estimates the costs for administering the AB 32 emissions reduction program annually. GHG emitters subject to the AB 32 GHG program are required to cover these costs. Consistent with the treatment in the ECAC for years 2013 through 2021 ECAC, PacifiCorp has included these costs in its ECAC.

[8] ARB requires a certified third-party independent auditor to verify and attest to the annual greenhouse gas emission report(s) submitted to ARB. Consistent with the treatment in the ECAC for the years 2013 through 2021, PacifiCorp has included these costs in its ECAC.

[9] In D.20-02-025, the Commission approved PacifiCorp's proposal to include PTCs and start-up fuel costs as part of the ECAC because they are closely related to NPC.

[10] *Id.*

The benefits realized through PacifiCorp's participation in the California Independent System Operator Energy Imbalance Market are embedded in actual NPC. The components of the ECAC and the factors affecting PacifiCorp's NPC are described in the direct testimony of Mr. Douglas R. Staples (Exhibit PAC/100).

**1) ECAC Balancing Rate for 2022**

NPC are defined as the sum of fuel expenses, wholesale purchase power expenses and wheeling expenses, less wholesale sales revenue. The ECAC provides PacifiCorp the opportunity to recover NPC in a timely and efficient manner, which allows PacifiCorp to continue to provide adequate, safe, and reliable service to its California customers.[11]

Rates for NPC are unbundled from other rates and are collected through the Energy Cost Adjustment Clause Tariff Rate Rider, Schedule ECAC-94. As authorized by the Commission in D.06-12-011, energy costs and revenues subject to the ECAC are accounted for in the ECAC balancing account. The ECAC balancing account is intended to be recovered through the Balancing Rate, which is presented for approval through the annual ECAC filing.

The ECAC includes two rate components: the Balancing Rate and the Offset Rate. The Balancing Rate is the rate that either returns to or recovers from customers the total accumulated deferral in the ECAC balancing account. The ECAC allows dollar-for-dollar recovery of actual NPC and fuel stock carrying charge. There is a monthly true-up of the forecasted NPC currently in rates with actual NPC. The Balancing Rate is updated each year if the new rate varies from the current rate by five percent or more. In this case, the Balancing Rate also includes a dollar-

[11] Joint Motion by PacifiCorp and Division of Ratepayer Advocates for Adoption of Settlement Agreement on Revenue Requirement Issues in A.05-11-022, at p. 10.

for-dollar recovery of costs associated with ARB Administrative Costs, net metering surplus compensation, and purchases of RECs for RPS compliance.[12]

PacifiCorp proposes a Balancing Rate effective January 1, 2022, of $4.25 per MWh, including PacifiCorp's billing factor.[13] When compared to the Balancing Rate currently in effect, the proposed change exceeds the five percent threshold.

**2) ECAC Offset Rate for 2021**

The second component of the ECAC, the Offset Rate, allows PacifiCorp to reset rates to reflect the forecast of NPC and fuel stock carrying charge for the upcoming year. To determine updated NPC, PacifiCorp incorporates updates to its:

(1) forward price curve;

(2) forecast loads;

(3) normalized hydro generation;

(4) forecast coal costs;

(5) wholesale sales and purchases of electricity and natural gas;

(6) thermal plant capabilities; and

(7) wheeling expenses.

The Offset Rate also includes costs projected in 2022 associated with ARB Administrative Costs and RECs purchased for RPS compliance.[14] A change in the Offset Rate can be made if the change in NPC for the upcoming twelve months exceeds five percent.[15]

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[12] Exhibit PAC/101 and Confidential Exhibit PAC/106.
[13] Exhibit PAC/100 at page 6.
[14] *See* Exhibit PAC/101 and Confidential Exhibit PAC/106.
[15] *See* D.06-12-011, 2.3.1 Energy Cost Adjustment Clause at Attachment A, p. 6; *see also* A.05-11-022, Joint Motion by PacifiCorp and Division of Ratepayer Advocates for Adoption of Settlement Agreement on Revenue Requirement Issues, Division of Ratepayer Advocates, Report of the Results of Operations for PacifiCorp, General Rate Case Test Year 2007, at 4-11.

PacifiCorp proposes an Offset Rate effective January 1, 2022, of $25.15 per MWh. California's allocated share of forecast NPC in the 2022 ECAC is approximately $22.3 million. The change in NPC compared to forecast NPC in the 2021 ECAC is an increase of 4.1 percent. However, as compared to the amount in present ECAC rates approved in D.20-12-004, the change in the Offset Rate for 2022 results in a rate decrease of approximately $5.1 million, which exceeds the five percent threshold.

### 3) Waiver Request of Certain Requirements in D.20-12-004

In previous annual ECAC filings, PacifiCorp used the Generation and Regulation Initiatives Tool (GRID), which is a production cost model, to forecast NPC. GRID simulated the operation of the Company's power system on an hourly basis. However, because of the limitations in the GRID model, PacifiCorp needed to engage in an iterative process to ensure the optimal marginal costs used for the coal plant dispatch were reflective of the Company's coal supply agreements. In D.20-12-004, the Commission stated that "[s]ince PacifiCorp must pay the full price of fuel for any purchases below minimum take requirements, we agree that ratepayers are likely to benefit from ensuring all minimum take requirements are met …"[16] To ensure proper transparency of the adjustments made to GRID, the Commission directed PacifiCorp to include in its ECAC applications going forward:

1. information on the marginal fuel cost assumed for each coal plant, the specific coal plants where adjustments were made to align forecasted generation with minimum take provisions, and the magnitude of adjustments made;
2. a GRID model run that depicts the NPC when adjustments are made to the Dispatch Tier meet minimum take provisions;
3. a GRID model run that depicts the NPC when the Dispatch Tier is based purely on marginal costs; and

[16] D.20-12-004 at 16.

4. a GRID model run that depicts the NPC when average fuel costs are utilized to forecast unit dispatch. PacifiCorp shall include this information.[17]

For the 2022 ECAC, PacifiCorp has transitioned to a new NPC modeling tool, Aurora, a third-party electric modeling and forecasting application. The Aurora model has the capability to model multiple tiered pricing contracts and volumetric contract provisions and has neither a "dispatch tier" nor a "costing tier" as GRID did. Because of the modeling enhancements gained by switching to the Aurora model, which does not make use of dispatch and costing tiers, the iterative adjustments to the GRID dispatch tier to account for the minimum take provisions of the coal supply agreements are not required to calculate NPC for the 2022 ECAC. As a result, there are no adjustments resulting from the iterative process used in previous ECACs to identify and quantify. Further, the previously ordered studies noted above are no longer relevant given the elimination of the iterative process or needed given the enhanced modeling provided by Aurora.[18] For a discussion of the Aurora model and the directives in D.20-12-004, please see Mr. Staples' direct testimony.

Therefore, the Company requests that the Commission waive these requirements from D. 20-12-004 for this and future ECAC applications.

**B. Costs and Revenues Associated with the Purchase and Sale of GHG Allowances**

Consistent with D.14-10-033, PacifiCorp has included in this application its forecast GHG allowance costs to be recovered from customers in 2022 and the California Climate Credit to be distributed to eligible customers in 2022.

GHG allowance costs associated with PacifiCorp's retail compliance obligation under California's Cap and Trade program are recovered from customers through Schedule GHG-92,

[17] *Id.,* at 16-17. Pursuant to D.20-12-004, PacifiCorp provided this information in the 2021 ECAC as supplemental testimony on February 5, 2021.
[18] The marginal costs fuel costs assumed for each coal plant are included in Mr. Staples' workpapers.

Surcharge to Recover Greenhouse Gas Carbon Pollution Permit Cost (GHG Surcharge). As part of this application, the Company requests authorization to update the GHG Surcharge effective January 1, 2022, as described in the supporting testimony of Company witnesses Ms. Mary M. Wiencke (Exhibit PAC/200) and Ms. Judith M. Ridenour (Exhibit PAC/600). As described in more detail in the direct testimony of Ms. Wiencke, these costs consist of a true-up related to actual GHG allowance costs and related interest set forth in the Company's 2021 Application (A.20-08-002) and a forecast of 2022 GHG allowance costs. The impact of the proposed change to the GHG Surcharge is an overall rate increase of $3.4 million.

PacifiCorp also respectfully requests authorization to distribute to eligible customers the California Climate Credit as described in the supporting testimony provided by Ms. Wiencke (Exhibit PAC/200) and Ms. Ridenour (Exhibit PAC/600).

The amount to be distributed consists of:

(1) a true-up related to actual GHG allowance revenue through May 31, 2021, and related interest;

(2) a forecast of 2022 GHG allowance revenue;

(3) a true-up related to actual customer outreach and administrative costs through May 31, 2021;

(4) a forecast of customer outreach and administrative costs for 2022; and

(5) funds set aside for energy efficiency programs developed under AB 693.

The GHG allowance revenue and reconciliation process is described in more detail in the direct testimony and supporting exhibits of Ms. Wiencke.[19] Customer outreach costs are discussed in more detail in the direct testimony and supporting exhibits of Ms. Ashley Rask.[20]

[19] Confidential Exhibits PAC/200 and PAC/205 through PAC/209.
[20] Exhibits PAC/300 through PAC/304.

Administrative costs are discussed in more detail in the direct testimony and supporting exhibits of Mr. Anthony B. Worthington.[21]

As discussed in Ms. Ridenour's testimony and supporting exhibits, the GHG allowance revenue, less administrative and outreach costs and funding for energy efficiency programs, is first returned to PacifiCorp's small business customers.[22] Based on the most recently approved small business assistance factor approved by the Commission in D.13-12-002 and continued for use in 2021 by D.20-10-022, small business customers will receive a monthly kilowatt-hour based California Climate Credit that offsets 50 percent of the GHG allowance costs they pay.[23] The total amount of the proposed small business California Climate Credit to be distributed in 2022 is approximately $0.6 million. The remainder of the revenue is returned to residential customers through the semi-annual on-bill California Climate Credit distributed in April and October of each year. The total amount of the proposed residential California Climate Credit to be distributed in 2022 is approximately $11.1 million. The proposed residential semi-annual, per-household California Climate Credit for 2022 is $154.58.

## IV. STATUTORY AND REGULATORY REQUIREMENTS

### A. Applicant 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 engages in the business of generating, transmitting, and distributing electric energy in portions of northern California and in Idaho, Oregon, Utah, Washington, and Wyoming. PacifiCorp's principal place of business is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232.

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[21] Exhibits PAC/400 through PAC/403.
[22] *See* Exhibits PAC/600 through PAC/607.
[23] An upcoming decision in R. 20-05-002 may change how the California Climate Credit is applied to small business customers. PacifiCorp will update proposed 2022 California Climate Credits as appropriate once the final decision in R.20-05-002 is issued.

Communications regarding this application should be addressed to:


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In addition, PacifiCorp respectfully requests that all data requests in this case 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

**B. Statutory and Procedural 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 Sections I through IV and is further described in the testimony, exhibits, and appendices supporting this application. The statutory and other authority under which this relief is being sought includes Rules 2.1 and 3.2, Sections 451, 454, and 701 of the California Public Utilities Code, and this Commission's prior decisions, orders, and resolutions. An officer of PacifiCorp has verified this application as required by Rules 1.11 and 2.1.

### C. Proposed Categorization, Need for Hearing, Issues to be Considered, Relevant Safety Considerations, and Proposed Schedule (Rule 2.1(c))

#### 1. Proposed Category of Proceeding

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." The issues in this proceeding relate to the proposed rate decrease necessary to allow PacifiCorp to recover its NPC and GHG allowance costs in 2022. This application also includes the proposed California Climate Credit for 2022.

#### 2. Need for Hearing

If no party objects to the proposed rates, hearings may not be necessary. PacifiCorp's application and the supporting appendices, testimony, and exhibits constitute a sufficient record for the Commission to rule on PacifiCorp's ECAC without the need for hearings.

#### 3. 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 help customers, employees, and stakeholders understand their own personal safety. In 2012 PacifiCorp received Prestigious Member Recognition from the National Safety Council for holding safety as a core value and making safety a priority in business. In 2013, 2015, and 2016 PacifiCorp received the

Occupational Excellence Achievement Award from the National Safety Council for working to reduce on the job injuries. PacifiCorp was recognized for its safety achievement by the Edison Electric Institute by being in the top 1 percent of the safest electrical utilities in America for 2015. 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 Occupational Health and Safety Act, and any applicable state health and safety act requirements, at all of its generation facilities. Certain safety codes may also be applicable to the operation of the Company's transmission and distribution facilities. PacifiCorp has developed standards that meet or exceed the National Electrical Safety Code. Employees are trained in work practice regulations along with Company construction standards to the highest standards and consistency.

The Company also works to develop teamwork to mitigate safety risks and has developed and implemented programs to continue improvement in safety. The Company continuously communicates safety goals in order to stay consistently on message across the organization. These programs include training and communicating from the top down, consistently delivering the same safety message and programs to all locations, and auditing the communications and programs. The Company sends daily emails to all of its employees noting accident reports and containing general reminders about safety. Other examples of the Company's commitment to safety include periodic emails with general safety tips for workplace and personal safety, safety committees for each floor of its corporate offices and field offices, annual safety training requirements which are linked to each employee's performance review, daily hazard assessment meetings for field offices, and annual evacuation drills.

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

### 4. Proposed Schedule

PacifiCorp proposes the following schedule, which allows for expedited Commission resolution of the Application:

| | |
|---|---|
| Application Filed | August 2, 2021 |
| Protest/Responses to Application | 30 days after notice of Application published in Daily Calendar |
| Prehearing Conference | September 21, 2021 |
| Scoping Memo | October 5, 2021 |
| Proposed Decision | November 9, 2021 |
| Final Commission Decision | December 9, 2021 |
| Rates Effective | January 1, 2022 |

## D. 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 by reference under Rule 2.2.

## E. Balance Sheet and Income Statement (Rule 3.2(a)(1))

A copy of PacifiCorp's recent financial statements, contained in the Quarterly Report on Form 10-Q, filed with the Securities and Exchange Commission (SEC), for the period ending March 31, 2021, is included as Appendix A.

## F. Present and Proposed Rates (Rule 3.2(a)(2) and (3))

A statement of PacifiCorp's present and proposed rates is included as Appendix B.

## G. Summary of Earnings (Rule 3.2(a)*(*5))

The statement of earnings included in this application as Appendix C is stated on a California-specific basis.

## H. List of Appendices, Testimony, and Exhibits

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

| | |
|---|---|
| Appendix A | PacifiCorp Form 10-Q for the period ending March 31, 2021 |
| Appendix B | Statement of Present and Proposed Rates |
| Appendix C | Summary of PacifiCorp's Earnings ending December 31, 2020 |
| Exhibits PAC/100 | Direct Testimony of Douglas R Staples |
| PAC/101 | California ECAC Offset/Balancing Rate Calculation |
| PAC/102 | Net Power Cost Analysis—Adjusted Actual 2019 Net Power Costs |
| PAC/103 | Net Power Cost Analysis—Adjusted Actual/Projected 2020 Net Power Costs |
| PAC/104 | Net Power Cost Analysis—Projected 2020 Net Power Costs |
| PAC/105 | 2021 California-allocated Net Power Costs |
| PAC/106 | ARB Administrative Costs (Confidential) |
| Exhibits PAC/200 | Direct Testimony of Mary M. Wiencke (Confidential) |
| PAC/201 | Commission Template C: Weighted Average Cost of Compliance Instruments (Confidential) |
| PAC/202 | Commission Template D-2: Annual GHG Emissions and Associated Compliance Obligation (Confidential) |
| PAC/203 | Summary of the GHG Allowance Costs Sub-Balancing Account (Confidential) |
| PAC/204 | 2022 Forecast Compliance Obligation and GHG Allowance Costs (Confidential) |
| PAC/205 | 2020 Recorded GHG Allowance Revenue (Confidential) |
| PAC/206 | 2021 Recorded/Forecast GHG Allowance Revenue (Confidential) |
| PAC/207 | Summary of the GHG Allowance Revenue Balancing Account (Confidential) |
| PAC/208 | 2022 Forecast GHG Allowance Revenue (Confidential) |
| PAC/209 | Commission Template D-5: History of Revenues, Costs, and Emissions Intensity (Confidential) |
| Exhibits PAC/300 | Direct Testimony of Ashley Rask |
| PAC/301 | 2013 – 2021 Recorded/Forecast Customer Outreach Costs |
| PAC/302 | 2022 Customer Outreach Activities and Estimated Costs |
| PAC/303 | 2022 Forecast Customer Outreach Costs |
| PAC/304 | Commission Template D-3: Detail of Outreach Costs |
| Exhibits PAC/400 | Direct Testimony of Anthony B. Worthington |
| PAC/401 | 2013 – 2021 Recorded/Forecast Administrative Costs |
| PAC/402 | 2022 Forecast Administrative Costs |
| PAC/403 | Commission Template D-3: Detail of Administrative Costs |

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| Exhibits PAC/500 | Direct Testimony of Dana M. Ralston (Highly Confidential) |
| Exhibits PAC/600 | Direct Testimony of Judith M. Ridenour |
| PAC/601 | Calculation of Proposed ECAC Adjustment Rates |
| PAC/602 | GHG Allowance Costs to be Recovered in Rates (Confidential) |
| PAC/603 | GHG Allowance Revenue to be Distributed Through the California Climate Credit |
| PAC/604 | Calculation of Proposed GHG Allowance Costs Surcharge and California Climate Credit Rates |
| PAC/605 | Commission Template D-1: Annual Allowance Revenue Receipts and Customer Returns (Confidential) |
| PAC/606 | Commission Template D-4: Forecast Revenue Requirement and Revenues by Rate Schedule |
| PAC/607 | Effects of Proposed Rate Change Distributed by Rate Schedule |

**I. Public Notice (Rule 3.2(b), (c) and (d))**

Certain cities and counties in the state of California will be affected by the rate changes resulting from this application. This includes the cities and towns of Yreka, Crescent City, Alturas, Mount Shasta, Weed, Dunsmuir, Fort Jones, Dorris, and Tulelake. Counties affected by this application are Siskiyou, Del Norte, Modoc, and Shasta. PacifiCorp will be providing notice to customers consistent with Rule 3.2(b), (c) and (d). Notice of the filing of this application will be: (1) served on the Attorney General and the Department of General Services when the state is a customer or subscriber whose rates would be affected by the proposed change; (2) served on the County Counsel (or District Attorney if the county has no County Counsel) and County Clerk, and the City Attorney and City Clerk, listed in the current roster published by the Secretary of State in each county and city in which the proposed change in rates is to be made effective; (3) published in a newspaper of general circulation in each county in PacifiCorp's service territory within which the rate changes would be effective; (4) included with regular bills mailed to all customers affected by the proposed changes or by electronically linking to notice of this application for customers that receive their bills electronically; and (5) served on any other persons whom PacifiCorp deems appropriate or as required by the Commission.

The bill inserts are required to include the application number assigned to this Application. Unless PacifiCorp receives the assigned application number for the Application within four days of filing, it may not be able to meet the deadline for completing the bill insert cycle within 45-days of filing the Application. Accordingly, PacifiCorp requests either: (a) expeditious assignment of an application number so that it can timely complete the bill inserts, or (b) a seven-day extension to complete this requirement.

**J. Statement under Rule 3.2(a)(10)**

If the Company is filing an application for authority to increase its rates, Rule 3.2(a)(10) requires PacifiCorp to state whether its request is limited to passing through to customers "only increased costs to the corporation for the services or commodities furnished by it." The Company is requesting an increase in the GHG surcharge to recover GHG allowance costs. PacifiCorp requests permission to pass through to customers increased costs to the corporation for the services or commodities furnished by it in serving its California retail customers.

**K. Commission Templates Included in Application**

In compliance with D.14-10-033, D.14-10-055, and D.15-01-024, PacifiCorp has prepared, and is submitting, the following Commission templates for this Application:

- Commission Template C: Weighted Average Cost of Compliance Instruments is provided as Confidential Exhibit PAC/201 to the direct testimony of Mary M. Wiencke.
- Commission Template D-1: Annual Allowance Revenue Receipts and Customer Returns is provided as Confidential Exhibit PAC/605 to the direct testimony of Judith M. Ridenour
- Commission Template D-2: Annual GHG Emissions and Associated Compliance Obligation is provided as Confidential Exhibit PAC/202 to the direct testimony of Mary M. Wiencke.

- Commission Template D-3: Detail of Outreach and Administrative Expenses. The template provided by the Commission included outreach and administrative costs in the same table. The table has been split into two tables, one for outreach and one for administrative costs so that each table may be included as an exhibit for the appropriate Company witness. Refer to Exhibit PAC/304 to the direct testimony of Ashley Rask for the detail of outreach costs. Refer to Exhibit PAC/403 to the direct testimony of Anthony B. Worthington for detail of administrative costs.

- Commission Template D-4: Forecast Revenue Requirement and Revenues by Rate Schedule is provided as Exhibit PAC/606 to the direct testimony of Judith M. Ridenour.

- Commission Template D-5: History of Revenues, Costs, and Emissions Intensity is provided as Exhibit PAC/209 to the direct testimony of Mary M. Wiencke.

## IV. CONCLUSION

Based on the information provided in this application, as well as the accompanying appendices, testimony, and exhibits, PacifiCorp respectfully requests that the Commission issue an order approving the proposed overall rate decrease to allow PacifiCorp timely recovery of its NPC through its approved ECAC and its GHG allowance surcharge. PacifiCorp also requests that the directives regarding the adjustments to the GRID and production of additional GRID runs in D.20-12-004 be waived. Finally, PacifiCorp respectfully requests approval of the California Climate Credit that returns revenue from the sale of GHG allowances to eligible customer classes.

Respectfully submitted this August 2, 2021, at San Francisco, California.

Carla Scarsella

By: Carla Scarsella

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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 Approval of its 2022 Energy Cost Adjustment Clause and Greenhouse Gas-Related Forecast and Reconciliation of Costs and Revenue | Application No. 21-08- ___<br>(Filed August 2, 2021) |

**VERIFICATION**

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

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

Executed on August 2, 2021, at Portland, Oregon.

Etta Lockey
Vice President, Regulation, Customer and Community Solutions

**DECLARATION OF ETTA LOCKEY (PACIFICORP)**

1. My name is Etta Lockey. My business address is 825 N.E. Multnomah Street, Suite 2000, Portland, Oregon 97232.

2. I am Vice President, Regulation, Customer and Community Solutions for PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company). PacifiCorp is a multi-jurisdictional utility providing electric retail service to customers in California, Idaho, Oregon, Utah, Washington, and Wyoming. PacifiCorp serves approximately 45,000 customers in portions of Del Norte, Modoc, Shasta, and Siskiyou Counties in northern California.

3. This declaration is based on my information and belief and is submitted in accordance with General Order (GO) 66-D of the California Public Utilities Commission (Commission).

4. Section 3.2 of GO 66-D provides that when a utility submits documents for which it seeks confidential treatment to the Commission or staff of the Commission outside of a formal proceeding, the utility must mark the document or applicable portions confidential and provide the basis for the confidential treatment specified. Additionally, any such request must be accompanied by a declaration signed by an officer of the requesting company. PacifiCorp therefore is providing this declaration along with the confidential information.

5. On August 2, 2021, PacifiCorp filed an Application for approval of its Energy Cost Adjustment Clause (ECAC) and Greenhouse Gas-Related (GHG) Forecast and Reconciliation of Costs and Revenue. The application includes Exhibit PAC/106 and workpapers, supporting the direct testimony of Douglas R. Staples, the direct testimony

(PAC/200) and supporting Exhibits (PAC/201 through PAC/209) of Mary M. Wiencke, the direct testimony (PAC/500) of Dana M. Ralston, and Exhibits PAC/602, PAC/605, and workpapers supporting the direct testimony of Judith M. Ridenour, all of which include either confidential or highly confidential information.

6. PacifiCorp is asserting that certain portions of the direct testimony and exhibits are confidential. Specifically, Douglas R. Staples' Exhibit PAC/106 includes PacifiCorp's actual and forecast Air Resource Board (ARB) administrative costs. Mary M. Wiencke's testimony (PAC/200) and supporting Exhibits (PAC/201 through PAC/209) contain market-sensitive information relating to PacifiCorp's GHG emissions compliance obligation and Greenhouse Gas (GHG) allowance costs. Dana M. Ralston's testimony (PAC/500) contains information contained in coal supply agreements and supporting information. Judith M. Ridenour's Exhibits PAC/602 and PAC/605 include forecast GHG revenue costs and GHG allowance costs. These exhibits and testimony contain market-sensitive and confidential information that would reveal to vendors the prices PacifiCorp has historically paid for items related to implementation of its GHG Cap-and-Trade obligation, as well as PacifiCorp's GHG-related costs, allowances, and revenues. This confidential information would also allow parties to determine PacifiCorp's current compliance position, which in turn could be used in future auctions to drive up the price PacifiCorp pays for auction allowances. Public disclosure would also compromise PacifiCorp's ongoing procurement process as it complies with the GHG Cap-and-Trade program, which would ultimately harm customers by unnecessarily inflating the prices paid by PacifiCorp. These exhibits also contain market-sensitive information that would reveal to market participants the terms of PacifiCorp coal supply

agreements, which, if made public, would adversely affect PacifiCorp's negotiation position regarding future fuel supply agreements and would harm customers by disadvantaging the Company as it transacts in the energy supply market.

7. Accordingly, PacifiCorp is asserting a claim of confidentiality in association with the submittal of Exhibits PAC/106, PAC/200, PAC/201, PAC/202, PAC/203, PAC/204, PAC/205, PAC/206, PAC/207, PAC/208, PAC 209, PAC/500, PAC/602, PAC/605, and supporting workpapers for Douglas R. Staples and Judith M. Ridenour accompanying the Application of PacifiCorp for Approval of its 2022 ECAC and GHG-Related Forecast and Reconciliation of Costs and Revenue filed on August 2, 2021.

8. The data for which PacifiCorp seeks confidential treatment are corporate confidential information and trade secrets protected from disclosure under California law.[1]

9. Information regarding requests for disclosure of the information for which PacifiCorp seeks confidential treatment should be directed to the following individuals:

California Dockets
PacifiCorp
californiadockets@pacificorp.com

Pooja Kishore
PacifiCorp
Regulatory Affairs Manager
pooja.kishore@pacificorp.com

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

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[1] Cal. Gov. Code §§ 6254 *et seq.* (e.g., Gov. Code §§ 6254(e), 6254(k), 6254.7; Cal. Evid. Code § 1060).

Executed in Portland, Oregon, on August 2, 2021.

Etta Lockey
Vice President, Regulation, Customer and
Community Solutions
PacifiCorp

# APPENDIX A

**UNITED STATES**
**SECURITIES AND EXCHANGE COMMISSION**
Washington, D.C. 20549

**FORM 10-Q**

☒ **Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the quarterly period ended March 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<br>State or other jurisdiction of incorporation or organization<br>Address of principal executive offices<br>Registrant's telephone number, including area code | IRS Employer Identification No. |
|---|---|---|
| **001-14881** | **BERKSHIRE HATHAWAY ENERGY COMPANY**<br>**(An Iowa Corporation)**<br>**666 Grand Avenue, Suite 500**<br>**Des Moines, Iowa 50309-2580**<br>**515-242-4300** | **94-2213782** |
| **001-05152** | **PACIFICORP**<br>**(An Oregon Corporation)**<br>**825 N.E. Multnomah Street**<br>**Portland, Oregon 97232**<br>**888-221-7070** | **93-0246090** |
| **333-90553** | **MIDAMERICAN FUNDING, LLC**<br>**(An Iowa Limited Liability Company)**<br>**666 Grand Avenue, Suite 500**<br>**Des Moines, Iowa 50309-2580**<br>**515-242-4300** | **47-0819200** |
| **333-15387** | **MIDAMERICAN ENERGY COMPANY**<br>**(An Iowa Corporation)**<br>**666 Grand Avenue, Suite 500**<br>**Des Moines, Iowa 50309-2580**<br>**515-242-4300** | **42-1425214** |
| **000-52378** | **NEVADA POWER COMPANY**<br>**(A Nevada Corporation)**<br>**6226 West Sahara Avenue**<br>**Las Vegas, Nevada 89146**<br>**702-402-5000** | **88-0420104** |
| **000-00508** | **SIERRA PACIFIC POWER COMPANY**<br>**(A Nevada Corporation)**<br>**6100 Neil Road**<br>**Reno, Nevada 89511**<br>**775-834-4011** | **88-0044418** |
| **001-37591** | **EASTERN ENERGY GAS HOLDINGS, LLC**<br>**(A Virginia Limited Liability Company)**<br>**6603 West Broad Street**<br>**Richmond, Virginia 23230**<br>**804-613-5100** | **46-3639580** |

**N/A**

(Former name or former address, if changed from last report)

| 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 |

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 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 April 29, 2021, 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 April 29, 2021, 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 April 29, 2021.

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 April 29, 2021, 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 April 29, 2021, 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 April 29, 2021, 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 April 29, 2021.

This combined Form 10-Q 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



### PART II

**Definition of Abbreviations and Industry Terms**

When used in Forward-Looking Statements, Part I - Items 2 through 3, and Part II - Items 1 through 6, the following terms have the definitions indicated.

| **Berkshire Hathaway Energy Company and Related Entities** | |
|---|---|
| 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 |
| Northern Powergrid | Northern Powergrid Holdings Company |
| BHE Pipeline Group | BHE GT&S, LLC, Northern Natural Gas Company and Kern River Gas Transmission Company |
| BHE GT&S | BHE GT&S, LLC |
| Northern Natural Gas | Northern Natural Gas Company |
| Kern River | Kern River Gas Transmission Company |
| BHE Transmission | BHE Canada Holdings Corporation and BHE U.S. Transmission, LLC |
| BHE Canada | BHE Canada Holdings Corporation |
| AltaLink | AltaLink, L.P. |
| BHE U.S. Transmission | BHE U.S. Transmission, LLC |
| BHE Renewables | BHE Renewables, LLC and CalEnergy Philippines |
| HomeServices | HomeServices of America, Inc. and its subsidiaries |
| Utilities | PacifiCorp and its subsidiaries, MidAmerican Energy Company, Nevada Power Company and its subsidiaries and Sierra Pacific Power Company and its subsidiaries |
| 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, Northern Natural Gas Company and Kern River Gas Transmission Company |
| GT&S Transaction | The acquisition of substantially all of the natural gas transmission and storage business of Dominion Energy and Dominion Questar, exclusive of the Questar Pipeline Group on November 1, 2020 |
| DEI | Dominion Energy, Inc. |
| Questar Pipeline Group | Dominion Energy Questar Pipeline, LLC and related entities |

**Certain Industry Terms**

| | |
|---|---|
| 2017 Tax Reform | The Tax Cuts and Jobs Act enacted on December 22, 2017, effective January 1, 2018 |
| AFUDC | Allowance for Funds Used During Construction |
| AUC | Alberta Utilities Commission |
| BART | Best Available Retrofit Technology |
| COVID-19 | Coronavirus Disease 2019 |
| 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 |
| Dth | Decatherm |
| EBA | Energy Balancing Account |
| ECAM | Energy Cost Adjustment Mechanism |
| EPA | United States Environmental Protection Agency |
| 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 |
| GTA | General Tariff Application |
| IPUC | Idaho Public Utilities Commission |
| ICC | Illinois Commerce Commission |
| IRP | Integrated Resource Plan |
| IUB | Iowa Utilities Board |
| kV | Kilovolt |
| KHSA | Klamath Hydroelectric Settlement Agreement |
| MW | Megawatt |
| MWh | Megawatt Hour |
| NAAQS | National Ambient Air Quality Standards |
| $NO_x$ | Nitrogen Oxides |
| Ofgem | Office of Gas and Electric Markets |
| OPUC | Oregon Public Utility Commission |
| PTC | Production Tax Credit |
| PUCN | Public Utilities Commission of Nevada |
| RAC | Renewable Adjustment Clause |
| REC | Renewable Energy Credit |
| RFP | Request for Proposal |
| RPS | Renewable Portfolio Standards |
| RRA | Renewable Energy Credit and Sulfur Dioxide Revenue Adjustment Mechanism |
| SCR | Selective Catalytic Reduction |
| SEC | United States Securities and Exchange Commission |
| SIP | State Implementation Plan |
| $SO_2$ | Sulfur Dioxide |
| UPSC | Utah Public Service Commission |
| WPSC | Wyoming Public Service Commission |
| WUTC | Washington Utilities and Transportation Commission |

## 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 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, earthquakes, explosions, landslides, an electromagnetic pulse, mining incidents, litigation, wars, terrorism, pandemics (including potentially in relation to COVID-19), embargoes, and cyber security attacks, data security breaches, disruptions, or other malicious acts;
- 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 the portion of the natural gas transmission and storage business acquired from DEI on November 1, 2020, and future acquired operations into a Registrant's business;
- the expected timing and likelihood of completion of the proposed transaction to acquire the remaining portion of DEI's natural gas transmission and storage business, including the ability to obtain the required clearance under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended;
- 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 Part II, Item 1A and other discussions contained in this Form 10-Q. 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.

## Item 1. Financial Statements

**Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations**

## Berkshire Hathaway Energy Company and its subsidiaries
## Consolidated Financial Section

## PART I

### Item 1. Financial Statements

### REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
Berkshire Hathaway Energy Company

**Results of Review of Interim Financial Information**

We have reviewed the accompanying consolidated balance sheet of Berkshire Hathaway Energy Company and subsidiaries (the "Company") as of March 31, 2021, the related consolidated statements of operations, comprehensive income, changes in equity, and cash flows for the three-month periods ended March 31, 2021 and 2020, and the related notes (collectively referred to as the "interim financial information"). Based on our reviews, we are not aware of any material modifications that should be made to the accompanying interim financial information for it to be in conformity with accounting principles generally accepted in the United States of America.

We have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheet of the Company as of December 31, 2020, and the related consolidated statements of operations, comprehensive income, changes in equity, and cash flows for the year then ended (not presented herein); and in our report dated February 26, 2021, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying consolidated balance sheet as of December 31, 2020, is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

**Basis for Review Results**

This interim financial information is the responsibility of the Company's management. We are a public accounting firm registered with the 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 reviews in accordance with standards of the PCAOB. A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the PCAOB, the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
April 30, 2021

**BERKSHIRE HATHAWAY ENERGY COMPANY AND SUBSIDIARIES**
**CONSOLIDATED BALANCE SHEETS (Unaudited)**
(Amounts in millions)

| | As of | |
|---|---|---|
| | **March 31, 2021** | **December 31, 2020** |
| **ASSETS** | | |
| **Current assets:** | | |
| Cash and cash equivalents | $ 1,276 | $ 1,290 |
| Restricted cash and cash equivalents | 117 | 140 |
| Trade receivables, net | 2,416 | 2,107 |
| Inventories | 1,110 | 1,168 |
| Mortgage loans held for sale | 2,065 | 2,001 |
| Other current assets | 3,236 | 2,741 |
| Total current assets | 10,220 | 9,447 |
| | | |
| Property, plant and equipment, net | 86,757 | 86,128 |
| Goodwill | 11,534 | 11,506 |
| Regulatory assets | 3,221 | 3,157 |
| Investments and restricted cash and cash equivalents and investments | 13,010 | 14,320 |
| Other assets | 2,780 | 2,758 |
| | | |
| **Total assets** | $ 127,522 | $ 127,316 |

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

**BERKSHIRE HATHAWAY ENERGY COMPANY AND SUBSIDIARIES**
**CONSOLIDATED BALANCE SHEETS (Unaudited) (continued)**
(Amounts in millions)

| | As of | |
|---|---|---|
| | March 31, 2021 | December 31, 2020 |
| **LIABILITIES AND EQUITY** | | |
| **Current liabilities:** | | |
| Accounts payable | $ 1,548 | $ 1,867 |
| Accrued interest | 642 | 555 |
| Accrued property, income and other taxes | 515 | 582 |
| Accrued employee expenses | 412 | 383 |
| Short-term debt | 2,699 | 2,286 |
| Current portion of long-term debt | 2,011 | 1,839 |
| Other current liabilities | 1,948 | 1,626 |
| Total current liabilities | 9,775 | 9,138 |
| | | |
| BHE senior debt | 12,999 | 12,997 |
| BHE junior subordinated debentures | 100 | 100 |
| Subsidiary debt | 34,351 | 34,930 |
| Regulatory liabilities | 7,355 | 7,221 |
| Deferred income taxes | 11,630 | 11,775 |
| Other long-term liabilities | 4,261 | 4,178 |
| Total liabilities | 80,471 | 80,339 |
| | | |
| Commitments and contingencies (Note 9) | | |
| | | |
| **Equity:** | | |
| BHE shareholders' equity: | | |
| Preferred stock - 100 shares authorized, $0.01 par value, 4 shares issued and outstanding | 3,750 | 3,750 |
| Common stock - 115 shares authorized, no par value, 76 shares issued and outstanding | — | — |
| Additional paid-in capital | 6,377 | 6,377 |
| Long-term income tax receivable | (658) | (658) |
| Retained earnings | 35,060 | 35,093 |
| Accumulated other comprehensive loss, net | (1,440) | (1,552) |
| Total BHE shareholders' equity | 43,089 | 43,010 |
| Noncontrolling interests | 3,962 | 3,967 |
| Total equity | 47,051 | 46,977 |
| | | |
| **Total liabilities and equity** | $ 127,522 | $ 127,316 |

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

**BERKSHIRE HATHAWAY ENERGY COMPANY AND SUBSIDIARIES**
**CONSOLIDATED STATEMENTS OF OPERATIONS (Unaudited)**
(Amounts in millions)

| | Three-Month Periods Ended March 31, | |
|---|---|---|
| | **2021** | **2020** |
| **Operating revenue:** | | |
| Energy | $ 4,849 | $ 3,634 |
| Real estate | 1,232 | 893 |
| Total operating revenue | 6,081 | 4,527 |
| | | |
| **Operating expenses:** | | |
| Energy: | | |
| Cost of sales | 1,569 | 1,038 |
| Operations and maintenance | 934 | 737 |
| Depreciation and amortization | 915 | 809 |
| Property and other taxes | 210 | 151 |
| Real estate | 1,120 | 873 |
| Total operating expenses | 4,748 | 3,608 |
| | | |
| **Operating income** | 1,333 | 919 |
| | | |
| **Other income (expense):** | | |
| Interest expense | (530) | (483) |
| Capitalized interest | 14 | 17 |
| Allowance for equity funds | 26 | 34 |
| Interest and dividend income | 21 | 20 |
| (Losses) gains on marketable securities, net | (1,118) | 27 |
| Other, net | 8 | (27) |
| Total other income (expense) | (1,579) | (412) |
| | | |
| **(Loss) income before income tax benefit and equity loss** | (246) | 507 |
| Income tax benefit | (535) | (184) |
| Equity loss | (179) | (18) |
| **Net income** | 110 | 673 |
| Net income attributable to noncontrolling interests | 106 | 3 |
| **Net income attributable to BHE shareholders** | 4 | 670 |
| Preferred dividends | 38 | — |
| **(Loss) earnings on common shares** | $ (34) | $ 670 |

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

**BERKSHIRE HATHAWAY ENERGY COMPANY AND SUBSIDIARIES**
**CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (Unaudited)**
(Amounts in millions)

| | Three-Month Periods Ended March 31, | |
|---|---|---|
| | **2021** | **2020** |
| Net income | $ 110 | $ 673 |
| Other comprehensive income (loss), net of tax: | | |
| Unrecognized amounts on retirement benefits, net of tax of $4 and $11 | 7 | 34 |
| Foreign currency translation adjustment | 91 | (548) |
| Unrealized gains (losses) on cash flow hedges, net of tax of $5 and $(10) | 14 | (33) |
| Total other comprehensive income (loss), net of tax | 112 | (547) |
| Comprehensive income | 222 | 126 |
| Comprehensive income attributable to noncontrolling interests | 106 | 3 |
| Comprehensive income attributable to BHE shareholders | $ 116 | $ 123 |

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

**BERKSHIRE HATHAWAY ENERGY COMPANY AND SUBSIDIARIES**
**CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY (Unaudited)**
(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, 2019** | $ — | $ — | $ 6,389 | $ (530) | $ 28,296 | $ (1,706) | $ 129 | $32,578 |
| Net income | — | — | — | — | 670 | — | 3 | 673 |
| Other comprehensive loss | — | — | — | — | — | (547) | — | (547) |
| Common stock purchases | — | — | (6) | — | (120) | — | — | (126) |
| Distributions | — | — | — | — | — | — | (5) | (5) |
| Other equity transactions | — | — | (1) | — | — | — | — | (1) |
| **Balance, March 31, 2020** | $ — | $ — | $ 6,382 | $ (530) | $ 28,846 | $ (2,253) | $ 127 | $32,572 |
| | | | | | | | | |
| **Balance, December 31, 2020** | $ 3,750 | $ — | $ 6,377 | $ (658) | $ 35,093 | $ (1,552) | $ 3,967 | $46,977 |
| Net income | — | — | — | — | 4 | — | 106 | 110 |
| Other comprehensive income | — | — | — | — | — | 112 | — | 112 |
| Preferred stock dividend | — | — | — | — | (38) | — | — | (38) |
| Distributions | — | — | — | — | — | — | (113) | (113) |
| Other equity transactions | — | — | — | — | 1 | — | 2 | 3 |
| **Balance, March 31, 2021** | $ 3,750 | $ — | $ 6,377 | $ (658) | $ 35,060 | $ (1,440) | $ 3,962 | $47,051 |

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

BERKSHIRE HATHAWAY ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS (Unaudited)
(Amounts in millions)

| | Three-Month Periods Ended March 31, 2021 | 2020 |
|---|---|---|
| **Cash flows from operating activities:** | | |
| Net income | $ 110 | $ 673 |
| Adjustments to reconcile net income to net cash flows from operating activities: | | |
| Losses (gains) on marketable securities, net | 1,118 | (27) |
| Depreciation and amortization | 927 | 821 |
| Allowance for equity funds | (26) | (34) |
| Equity loss, net of distributions | 221 | 29 |
| Changes in regulatory assets and liabilities | (9) | — |
| Deferred income taxes and amortization of investment tax credits | (135) | 47 |
| Other, net | 9 | 63 |
| Changes in other operating assets and liabilities, net of effects from acquisitions: | | |
| Trade receivables and other assets | (249) | (118) |
| Derivative collateral, net | 14 | (19) |
| Pension and other postretirement benefit plans | (21) | (23) |
| Accrued property, income and other taxes, net | (453) | (364) |
| Accounts payable and other liabilities | 19 | 117 |
| Net cash flows from operating activities | 1,525 | 1,165 |
| **Cash flows from investing activities:** | | |
| Capital expenditures | (1,295) | (1,356) |
| Purchases of marketable securities | (128) | (188) |
| Proceeds from sales of marketable securities | 104 | 180 |
| Equity method investments | (26) | (153) |
| Other, net | (29) | 43 |
| Net cash flows from investing activities | (1,374) | (1,474) |
| **Cash flows from financing activities:** | | |
| Proceeds from BHE senior debt | — | 3,231 |
| Repayments of BHE senior debt | (450) | (350) |
| Common stock purchases | — | (126) |
| Proceeds from subsidiary debt | — | 1,093 |
| Repayments of subsidiary debt | (26) | (1,347) |
| Net proceeds from (repayments of) short-term debt | 409 | (1,109) |
| Distributions to noncontrolling interests | (115) | (2) |
| Other, net | (9) | (32) |
| Net cash flows from financing activities | (191) | 1,358 |
| Effect of exchange rate changes | 1 | (13) |
| **Net change in cash and cash equivalents and restricted cash and cash equivalents** | (39) | 1,036 |
| **Cash and cash equivalents and restricted cash and cash equivalents at beginning of period** | 1,445 | 1,268 |
| **Cash and cash equivalents and restricted cash and cash equivalents at end of period** | $ 1,406 | $ 2,304 |

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

## (1) General

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 ("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 (which primarily consists of BHE Renewables, LLC and CalEnergy Philippines) 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.

The unaudited Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") for interim financial information and the United States Securities and Exchange Commission's rules and regulations for Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all of the disclosures required by GAAP for annual financial statements. Management believes the unaudited Consolidated Financial Statements contain all adjustments (consisting only of normal recurring adjustments) considered necessary for the fair presentation of the unaudited Consolidated Financial Statements as of March 31, 2021 and for the three-month periods ended March 31, 2021 and 2020. The results of operations for the three-month period ended March 31, 2021 are not necessarily indicative of the results to be expected for the full year.

The preparation of the unaudited Consolidated Financial Statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the unaudited Consolidated Financial Statements and the reported amounts of revenue and expenses during the period. Actual results may differ from the estimates used in preparing the unaudited Consolidated Financial Statements. Note 2 of Notes to Consolidated Financial Statements included in the Company's Annual Report on Form 10-K for the year ended December 31, 2020 describes the most significant accounting policies used in the preparation of the unaudited Consolidated Financial Statements. There have been no significant changes in the Company's assumptions regarding significant accounting estimates and policies during the three-month period ended March 31, 2021.

## (2) Business Acquisition

*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") (formerly known as Dominion Energy Transmission, Inc.) and Carolina Gas Transmission, LLC (formerly known as Dominion Energy 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") (formerly known as Dominion Energy Cove Point LNG, LP), 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 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, which is currently anticipated in the first half of 2021, 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 is 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 is included in other current assets on the Consolidated Balance Sheet as of March 31, 2021 and December 31, 2020, to Dominion Questar on November 2, 2020. If the Q-Pipe Transaction does not close, Dominion Questar has agreed to repay all or (depending on 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. If HSR Approval has not been obtained by June 30, 2021, upon BHE's written request, Dominion Questar will seek alternative buyers for all or a material portion of the Questar Pipeline Group (an "Alternative Transaction"). The Purchase Price Repayment Amount may be paid in cash or in shares of common stock, no par value, of DEI, or a combination thereof, subject to certain limitations as to stock repayments set forth in the Q-Pipe Purchase Agreement; provided any payment on or after December 15, 2021 must be paid in cash only.

The assets acquired in the GT&S Transaction include (i) approximately 5,400 miles of operated natural gas transmission, gathering and storage pipelines with approximately 12.5 billion cubic feet ("Bcf") per day of design capacity; (ii) 420 Bcf of operated natural gas storage design capacity, of which 306 Bcf is owned by BHE GT&S; and (iii) an LNG export, import and storage facility with LNG storage capacity of approximately 14.6 billions of cubic feet equivalent.

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.

Included in BHE's Consolidated Statement of Operations within the BHE Pipeline Group reportable segment for the three-month periods ended March 31, 2021, is operating revenue and net income attributable to BHE shareholders of $559 million and $107 million, respectively, as a result of including BHE GT&S from November 1, 2020.

*Preliminary 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 Federal Energy Regulatory Commission ("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 fair value of certain contracts and property, plant and equipment related to non-regulated operations, certain regulatory assets and other items included in rate base, an equity method investment and deferred income tax amounts are provisional and are subject to revision for up to 12 months following the acquisition date until the related valuations are completed. These items may be adjusted through regulatory assets or liabilities, to the extent recoverable in rates, or goodwill provided additional information is obtained about the facts and circumstances that existed as of the acquisition date. Such information includes, but is not limited to, the receipt of further information regarding the fair value of the contracts and property, plant and equipment related to non-regulated operations, the equity method investment and any associated deferred income tax amounts as well as the evolution of the rate-making process for regulated operations.

The following table summarizes the preliminary 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 | $ 569 |
| Property, plant and equipment | 9,254 |
| Goodwill | 1,732 |
| Regulatory assets | 108 |
| Deferred income taxes | 275 |
| Other long-term assets | 1,424 |
| Total assets | 13,362 |
| | |
| Current liabilities, including current portion of long-term debt of $1,200 | 1,567 |
| Long-term debt, less current portion | 4,415 |
| Regulatory liabilities | 661 |
| Other long-term liabilities | 289 |
| Total liabilities | 6,932 |
| Noncontrolling interest | 3,916 |
| Net assets acquired | $ 2,514 |

*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):

| | Three-Month Period Ended March 31, 2020 |
|---|---|
| Operating revenue | $ 5,056 |
| Net income attributable to BHE shareholders | $ 773 |

**(3) Property, Plant and Equipment, Net**

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

| | Depreciable Life | As of March 31, 2021 | As of December 31, 2020 |
|---|---|---|---|
| **Regulated assets:** | | | |
| Utility generation, transmission and distribution systems | 5-80 years | $ 87,898 | $ 86,730 |
| Interstate natural gas pipeline assets | 3-80 years | 16,712 | 16,667 |
| | | 104,610 | 103,397 |
| Accumulated depreciation and amortization | | (31,653) | (30,662) |
| Regulated assets, net | | 72,957 | 72,735 |
| | | | |
| **Nonregulated assets:** | | | |
| Independent power plants | 5-30 years | 7,034 | 7,012 |
| Other assets | 3-40 years | 5,794 | 5,659 |
| | | 12,828 | 12,671 |
| Accumulated depreciation and amortization | | (2,337) | (2,586) |
| Nonregulated assets, net | | 10,491 | 10,085 |
| | | | |
| Net operating assets | | 83,448 | 82,820 |
| Construction work-in-progress | | 3,309 | 3,308 |
| Property, plant and equipment, net | | $ 86,757 | $ 86,128 |

Construction work-in-progress includes $2.9 billion as of March 31, 2021 and $3.2 billion as of December 31, 2020, related to the construction of regulated assets.

## (4) Investments and Restricted Cash and Cash Equivalents and Investments

Investments and restricted cash and cash equivalents and investments consists of the following (in millions):

| | As of | |
|---|---|---|
| | March 31, 2021 | December 31, 2020 |
| **Investments:** | | |
| BYD Company Limited common stock | $ 4,773 | $ 5,897 |
| Rabbi trusts | 452 | 440 |
| Other | 288 | 263 |
| Total investments | 5,513 | 6,600 |
| | | |
| **Equity method investments:** | | |
| BHE Renewables tax equity investments | 5,399 | 5,626 |
| Iroquois Gas Transmission System, L.P. | 586 | 580 |
| Electric Transmission Texas, LLC | 581 | 594 |
| JAX LNG, LLC | 80 | 75 |
| Bridger Coal Company | 68 | 74 |
| Other | 113 | 118 |
| Total equity method investments | 6,827 | 7,067 |
| | | |
| **Restricted cash and cash equivalents and investments:** | | |
| Quad Cities Station nuclear decommissioning trust funds | 697 | 676 |
| Other restricted cash and cash equivalents | 130 | 155 |
| Total restricted cash and cash equivalents and investments | 827 | 831 |
| | | |
| Total investments and restricted cash and cash equivalents and investments | $ 13,167 | $ 14,498 |
| | | |
| **Reflected as:** | | |
| Current assets | $ 157 | $ 178 |
| Noncurrent assets | 13,010 | 14,320 |
| Total investments and restricted cash and cash equivalents and investments | $ 13,167 | $ 14,498 |

*Investments*

(Losses) gains on marketable securities, net recognized during the period consists of the following (in millions):

| | Three-Month Periods Ended March 31, | |
|---|---|---|
| | 2021 | 2020 |
| Unrealized (losses) gains recognized on marketable securities still held at the reporting date | $ (1,119) | $ 25 |
| Net gains recognized on marketable securities sold during the period | 1 | 2 |
| (Losses) gains on marketable securities, net | $ (1,118) | $ 27 |

*Equity Method Investments*

The Company has invested in projects sponsored by third parties, commonly referred to as tax equity investments. 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. Certain of the Company's tax equity investments are located in Texas and have physical settlement hedge obligations that were negatively impacted due to production shortfalls during periods of extreme market pricing volatility as a result of the February 2021 polar vortex weather event. The Company recognized pre-tax equity losses of $218 million, or after-tax losses of $23 million inclusive of production tax credits ("PTCs") of $148 million and other income tax benefits of $47 million, during the three-month period ended March 31, 2021, on its tax equity investments, largely due to the February 2021 polar vortex weather event. The losses for the impacted tax equity investments were based upon the terms of each partnership agreement, as amended, and are subject to change as project-by-project discussions are ongoing among the Company and the respective hedge provider and project sponsor. As of March 31, 2021, the carrying value of the impacted tax equity investments totaled $2.8 billion.

*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 March 31, 2021 and December 31, 2020, consist substantially of funds restricted for the purpose of constructing solid waste facilities under tax-exempt bond obligation agreements and debt service obligations for certain of the Company's nonregulated renewable energy projects. A reconciliation of cash and cash equivalents and restricted cash and cash equivalents as of March 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 | |
|---|---|---|
| | **March 31, 2021** | **December 31, 2020** |
| Cash and cash equivalents | $ 1,276 | $ 1,290 |
| Restricted cash and cash equivalents | 117 | 140 |
| Investments and restricted cash and cash equivalents and investments | 13 | 15 |
| Total cash and cash equivalents and restricted cash and cash equivalents | $ 1,406 | $ 1,445 |

## (5) Recent Financing Transactions

*Long-Term Debt*

In April 2021, Northern Natural Gas issued $550 million of 3.40% Senior Bonds due October 2051. Northern Natural Gas used the net proceeds to early redeem in April 2021 all of its $200 million, 4.25% Senior Notes originally due June 2021 and for general corporate purposes.

*Credit Facilities*

In April 2021, AltaLink Investments, L.P. extended, with lender consent, the expiration date for its existing C$200 million one-year revolving credit facility to April 2022, by exercising a one-year extension option.

## (6) Income Taxes

The effective income tax rate for the three-month period ended March 31, 2021, is 217% and results from a $535 million income tax benefit associated with a $246 million pre-tax loss, primarily relating to a pre-tax unrealized loss of $1,124 million on the Company's investment in BYD Company Limited. The $535 million income tax benefit is primarily comprised of a $52 million benefit (21%) from the application of the statutory income tax rate to the pre-tax loss, a $334 million benefit (136%) from income tax credits and a $51 million benefit (21%) from state income tax benefits, net of federal income tax impacts.

A reconciliation of the federal statutory income tax rate to the effective income tax rate applicable to income before income tax benefit is as follows:

| | Three-Month Periods Ended March 31, | |
|---|---|---|
| | 2021 | 2020 |
| Federal statutory income tax rate | 21 % | 21 % |
| Income tax credits | 136 | (46) |
| State income tax, net of federal income tax impacts | 21 | — |
| Income tax effect of foreign income | 6 | (3) |
| Effects of ratemaking | 10 | (8) |
| Equity income | 15 | (1) |
| Noncontrolling interest | 9 | — |
| Other, net | (1) | 1 |
| Effective income tax rate | 217 % | (36)% |

Income tax credits relate primarily to PTCs 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 three-month periods ended March 31, 2021 and 2020 totaled $315 million and $233 million, respectively.

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 made no payments for federal income taxes to Berkshire Hathaway for the three-month period ended March 31, 2021, and made payments for federal income taxes to Berkshire Hathaway totaling $100 million for the three-month period ended March 31, 2020.

## (7) Employee Benefit Plans

*Domestic Operations*

Net periodic benefit cost (credit) for the domestic pension and other postretirement benefit plans included the following components (in millions):

| | Three-Month Periods Ended March 31, | |
|---|---|---|
| | 2021 | 2020 |
| **Pension:** | | |
| Service cost | $ 7 | $ 3 |
| Interest cost | 20 | 23 |
| Expected return on plan assets | (33) | (35) |
| Net amortization | 6 | 9 |
| Net periodic benefit cost | $ — | $ — |
| **Other postretirement:** | | |
| Service cost | $ 2 | $ 1 |
| Interest cost | 5 | 6 |
| Expected return on plan assets | (5) | (9) |
| Net amortization | (1) | (1) |
| Net periodic benefit cost (credit) | $ 1 | $ (3) |

Amounts other than the service cost for pension and other postretirement benefit plans are recorded in Other, net in the Consolidated Statements of Operations. Employer contributions to the domestic pension and other postretirement benefit plans are expected to be $13 million and $13 million, respectively, during 2021. As of March 31, 2021, $3 million and $3 million of contributions had been made to the domestic pension and other postretirement benefit plans, respectively.

*Foreign Operations*

Net periodic benefit credit for the United Kingdom pension plan included the following components (in millions):

| | Three-Month Periods Ended March 31, | |
|---|---|---|
| | 2021 | 2020 |
| Service cost | $ 4 | $ 4 |
| Interest cost | 8 | 10 |
| Expected return on plan assets | (28) | (25) |
| Net amortization | 14 | 10 |
| Net periodic benefit credit | $ (2) | $ (1) |

Amounts other than the service cost for the United Kingdom pension plan are recorded in Other, net in the Consolidated Statements of Operations. Employer contributions to the United Kingdom pension plan are expected to be £50 million during 2021. As of March 31, 2021, £11 million, or $15 million, of contributions had been made to the United Kingdom pension plan.

## (8) 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 March 31, 2021** | | | | | |
| **Assets:** | | | | | |
| Commodity derivatives | $ 1 | $ 72 | $ 154 | $ (18) | $ 209 |
| Foreign currency exchange rate derivatives | — | 12 | — | — | 12 |
| Interest rate derivatives | — | 33 | 47 | — | 80 |
| Mortgage loans held for sale | — | 2,065 | — | — | 2,065 |
| Money market mutual funds[(2)] | 807 | — | — | — | 807 |
| Debt securities: | | | | | |
| United States government obligations | 210 | — | — | — | 210 |
| International government obligations | — | 5 | — | — | 5 |
| Corporate obligations | — | 71 | — | — | 71 |
| Municipal obligations | — | 2 | — | — | 2 |
| Agency, asset and mortgage-backed obligations | — | 5 | — | — | 5 |
| Equity securities: | | | | | |
| United States companies | 395 | — | — | — | 395 |
| International companies | 4,780 | — | — | — | 4,780 |
| Investment funds | 256 | — | — | — | 256 |
| | $ 6,449 | $ 2,265 | $ 201 | $ (18) | $ 8,897 |
| **Liabilities:** | | | | | |
| Commodity derivatives | $ — | $ (90) | $ (30) | $ 39 | $ (81) |
| Foreign currency exchange rate derivatives | — | (1) | — | — | (1) |
| Interest rate derivatives | (3) | (14) | (6) | — | (23) |
| | $ (3) | $ (105) | $ (36) | $ 39 | $ (105) |

| | Input Levels for Fair Value Measurements | | | | |
|---|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Other[(1)] | Total |
| **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[(2)] | 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 $21 million and $35 million as of March 31, 2021 and December 31, 2020, respectively.

(2) Amounts are included in cash and cash equivalents; other current assets; and noncurrent investments and restricted cash and investments on the Consolidated Balance Sheets. The fair value of these money market mutual funds approximates cost.

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 assets and liabilities measured at fair value on a recurring basis using significant Level 3 inputs (in millions):

| | Three-Month Periods Ended March 31, | |
|---|---|---|
| | Commodity Derivatives | Interest Rate Derivatives |
| **2021:** | | |
| **Beginning balance** | $ 116 | $ 62 |
| Changes included in earnings[(1)] | (6) | (21) |
| Changes in fair value recognized in OCI | (1) | — |
| Changes in fair value recognized in net regulatory assets | 16 | — |
| Settlements | (1) | — |
| **Ending balance** | $ 124 | $ 41 |
| **2020:** | | |
| **Beginning balance** | $ 97 | $ 14 |
| Changes included in earnings[(1)] | (3) | 31 |
| Changes in fair value recognized in net regulatory assets | (40) | — |
| Purchases | 2 | — |
| Settlements | (4) | — |
| **Ending balance** | $ 52 | $ 45 |

(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 Balance Sheets. 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 (in millions):

| | As of March 31, 2021 | | As of December 31, 2020 | |
|---|---|---|---|---|
| | Carrying Value | Fair Value | Carrying Value | Fair Value |
| Long-term debt | $ 49,461 | $ 55,926 | $ 49,866 | $ 60,633 |

## (9) Commitments and Contingencies

*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. The Company 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, including residences, destroyed; 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. 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.

As of March 31, 2021, 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 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 by January 16, 2021 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. On January 13, 2021, the new license transfer application was filed with the FERC, notifying it that PacifiCorp and the KRRC are not accepting co-licensee status under FERC's July 2020 order, and instead are seeking the license transfer outcome described in the new license transfer application. 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.

*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.

## (10) Revenue from Contracts with Customers

*Energy Products and Services*

The following table summarizes the Company's energy products and services revenue from contracts with customers ("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 13 (in millions):

| | For the Three-Month Period Ended March 31, 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 | $ 1,145 | $ 452 | $ 511 | $ — | $ — | $ — | $ — | $ — | $ 2,108 |
| Retail gas | — | 460 | 38 | — | — | — | — | — | 498 |
| Wholesale | 36 | 125 | 15 | — | 17 | — | — | — | 193 |
| Transmission and distribution | 25 | 15 | 21 | 263 | — | 172 | — | — | 496 |
| Interstate pipeline | — | — | — | — | 815 | — | — | (41) | 774 |
| Other | 23 | — | — | — | 2 | — | — | — | 25 |
| Total Regulated | 1,229 | 1,052 | 585 | 263 | 834 | 172 | — | (41) | 4,094 |
| Nonregulated | — | 10 | — | 10 | 237 | 8 | 166 | 187 | 618 |
| Total Customer Revenue | 1,229 | 1,062 | 585 | 273 | 1,071 | 180 | 166 | 146 | 4,712 |
| Other revenue | 13 | 5 | 6 | 27 | 22 | — | 24 | 40 | 137 |
| Total | $ 1,242 | $ 1,067 | $ 591 | $ 300 | $ 1,093 | $ 180 | $ 190 | $ 186 | $ 4,849 |

| | For the Three-Month Period Ended March 31, 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 | $ 1,122 | $ 410 | $ 529 | $ — | $ — | $ — | $ — | $ — | $ 2,061 |
| Retail gas | — | 187 | 47 | — | — | — | — | — | 234 |
| Wholesale | — | 64 | 14 | — | — | — | — | (1) | 77 |
| Transmission and distribution | 22 | 15 | 23 | 233 | — | 169 | — | — | 462 |
| Interstate pipeline | — | — | — | — | 400 | — | — | (48) | 352 |
| Other | 26 | — | 1 | — | — | — | — | — | 27 |
| Total Regulated | 1,170 | 676 | 614 | 233 | 400 | 169 | — | (49) | 3,213 |
| Nonregulated | — | 6 | 1 | 7 | — | 3 | 159 | 127 | 303 |
| Total Customer Revenue | 1,170 | 682 | 615 | 240 | 400 | 172 | 159 | 78 | 3,516 |
| Other revenue | 36 | 4 | 7 | 26 | 1 | — | 19 | 25 | 118 |
| Total | $ 1,206 | $ 686 | $ 622 | $ 266 | $ 401 | $ 172 | $ 178 | $ 103 | $ 3,634 |

(1) The BHE and Other reportable segment represents amounts related principally to other entities, corporate functions and intersegment eliminations.

*Real Estate Services*

The following table summarizes the Company's real estate services Customer Revenue by line of business (in millions):

| | HomeServices | |
|---|---|---|
| | Three-Month Periods Ended March 31, | |
| | 2021 | 2020 |
| Customer Revenue: | | |
| Brokerage | $ 1,022 | $ 777 |
| Franchise | 18 | 16 |
| Total Customer Revenue | 1,040 | 793 |
| Mortgage and other revenue | 192 | 100 |
| Total | $ 1,232 | $ 893 |

*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 March 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 | $ 2,521 | $ 20,918 | $ 23,439 |
| BHE Transmission | 513 | — | 513 |
| Total | $ 3,034 | $ 20,918 | $ 23,952 |

**(11) BHE Shareholders' Equity**

For the three-month period ended March 31, 2020, BHE repurchased 180,358 shares of its common stock for $126 million.

**(12) Components of Other Comprehensive Income (Loss), Net**

The following table shows the change in accumulated other comprehensive income (loss) attributable to BHE shareholders by each component of other comprehensive income (loss), net of applicable income tax (in millions):

| | Unrecognized Amounts on Retirement Benefits | Foreign Currency Translation Adjustment | Unrealized (Losses) Gains on Cash Flow Hedges | AOCI Attributable To BHE Shareholders, Net |
|---|---|---|---|---|
| **Balance, December 31, 2019** | $ (417) | $ (1,296) | $ 7 | $ (1,706) |
| Other comprehensive income (loss) | 34 | (548) | (33) | (547) |
| **Balance, March 31, 2020** | $ (383) | $ (1,844) | $ (26) | $ (2,253) |
| | | | | |
| **Balance, December 31, 2020** | $ (482) | $ (1,062) | $ (8) | $ (1,552) |
| Other comprehensive income | 7 | 91 | 14 | 112 |
| **Balance, March 31, 2021** | $ (475) | $ (971) | $ 6 | $ (1,440) |

## (13) Segment Information

The Company's reportable segments with foreign operations include Northern Powergrid, whose business is principally in the United Kingdom, BHE Transmission, whose business includes operations in Canada, and BHE Renewables, whose business includes operations in the Philippines. 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):

| | Three-Month Periods Ended March 31, | |
|---|---|---|
| | 2021 | 2020 |
| **Operating revenue:** | | |
| PacifiCorp | $ 1,242 | $ 1,206 |
| MidAmerican Funding | 1,067 | 686 |
| NV Energy | 591 | 622 |
| Northern Powergrid | 300 | 266 |
| BHE Pipeline Group | 1,093 | 401 |
| BHE Transmission | 180 | 172 |
| BHE Renewables | 190 | 178 |
| HomeServices | 1,232 | 893 |
| BHE and Other[1] | 186 | 103 |
| Total operating revenue | $ 6,081 | $ 4,527 |
| **Depreciation and amortization:** | | |
| PacifiCorp | $ 264 | $ 252 |
| MidAmerican Funding | 207 | 176 |
| NV Energy | 136 | 124 |
| Northern Powergrid | 71 | 63 |
| BHE Pipeline Group | 118 | 64 |
| BHE Transmission | 58 | 60 |
| BHE Renewables | 60 | 71 |
| HomeServices | 11 | 11 |
| BHE and Other[1] | 2 | — |
| Total depreciation and amortization | $ 927 | $ 821 |

| | Three-Month Periods Ended March 31, | |
|---|---|---|
| | 2021 | 2020 |
| **Operating income:** | | |
| PacifiCorp | $ 234 | $ 234 |
| MidAmerican Funding | 48 | 102 |
| NV Energy | 70 | 79 |
| Northern Powergrid | 151 | 132 |
| BHE Pipeline Group | 618 | 249 |
| BHE Transmission | 81 | 76 |
| BHE Renewables | 33 | 17 |
| HomeServices | 112 | 20 |
| BHE and Other[1] | (14) | 10 |
| Total operating income | 1,333 | 919 |
| Interest expense | (530) | (483) |
| Capitalized interest | 14 | 17 |
| Allowance for equity funds | 26 | 34 |
| Interest and dividend income | 21 | 20 |
| (Losses) gains on marketable securities, net | (1,118) | 27 |
| Other, net | 8 | (27) |
| Total (loss) income before income tax benefit and equity loss | $ (246) | $ 507 |
| **Interest expense:** | | |
| PacifiCorp | $ 107 | $ 102 |
| MidAmerican Funding | 78 | 81 |
| NV Energy | 52 | 58 |
| Northern Powergrid | 33 | 32 |
| BHE Pipeline Group | 38 | 14 |
| BHE Transmission | 38 | 38 |
| BHE Renewables | 40 | 42 |
| HomeServices | 1 | 5 |
| BHE and Other[1] | 143 | 111 |
| Total interest expense | $ 530 | $ 483 |
| **(Loss) earnings on common shares:** | | |
| PacifiCorp | $ 169 | $ 176 |
| MidAmerican Funding | 144 | 150 |
| NV Energy | 34 | 20 |
| Northern Powergrid | 104 | 87 |
| BHE Pipeline Group | 383 | 179 |
| BHE Transmission | 59 | 55 |
| BHE Renewables | 16 | 95 |
| HomeServices | 84 | 10 |
| BHE and Other | (1,027) | (102) |
| (Loss) earnings on common shares | $ (34) | $ 670 |

| | As of | |
|---|---|---|
| | March 31, 2021 | December 31, 2020 |
| **Assets:** | | |
| PacifiCorp | $ 26,956 | $ 26,862 |
| MidAmerican Funding | 24,098 | 23,530 |
| NV Energy | 14,594 | 14,501 |
| Northern Powergrid | 8,980 | 8,782 |
| BHE Pipeline Group | 19,651 | 19,541 |
| BHE Transmission | 9,341 | 9,208 |
| BHE Renewables | 11,935 | 12,004 |
| HomeServices | 5,186 | 4,955 |
| BHE and Other[(1)] | 6,781 | 7,933 |
| Total assets | $ 127,522 | $ 127,316 |

(1) The differences between the reportable segment amounts and the consolidated amounts, described as BHE and Other, relate principally to other entities, including MidAmerican Energy Services, LLC, corporate functions and intersegment eliminations.

| | Three-Month Periods Ended March 31, | |
|---|---|---|
| | 2021 | 2020 |
| **Operating revenue by country:** | | |
| United States | $ 5,597 | $ 4,089 |
| United Kingdom | 300 | 266 |
| Canada | 177 | 171 |
| Philippines and other | 7 | 1 |
| Total operating revenue by country | $ 6,081 | $ 4,527 |
| | | |
| **(Loss) income before income tax benefit and equity loss by country:** | | |
| United States | $ (423) | $ 354 |
| United Kingdom | 132 | 109 |
| Canada | 39 | 40 |
| Philippines and other | 6 | 4 |
| Total (loss) income before income tax benefit and equity loss by country | $ (246) | $ 507 |

The following table shows the change in the carrying amount of goodwill by reportable segment for the three-month period ended March 31, 2021 (in millions):

| | PacifiCorp | MidAmerican Funding | NV Energy | Northern Powergrid | BHE Pipeline Group | BHE Transmission | BHE Renewables | HomeServices | Total |
|---|---|---|---|---|---|---|---|---|---|
| **December 31, 2020** | $ 1,129 | $ 2,102 | $ 2,369 | $ 1,000 | $ 1,803 | $ 1,551 | $ 95 | $ 1,457 | $ 11,506 |
| Acquisitions | — | — | — | — | — | — | — | 1 | 1 |
| Foreign currency translation | — | — | — | 6 | — | 21 | — | — | 27 |
| **March 31, 2021** | $ 1,129 | $ 2,102 | $ 2,369 | $ 1,006 | $ 1,803 | $ 1,572 | $ 95 | $ 1,458 | $ 11,534 |

**Item 2. 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 unaudited Consolidated Financial Statements and Notes to Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q. The Company's actual results in the future could differ significantly from the historical results.

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. 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, corporate functions and intersegment eliminations.

**Results of Operations for the First Quarter of 2021 and 2020**

Overview

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

| | First Quarter | | | |
|---|---|---|---|---|
| | 2021 | 2020 | Change | |
| **Operating revenue:** | | | | |
| PacifiCorp | $ 1,242 | $ 1,206 | $ 36 | 3 % |
| MidAmerican Funding | 1,067 | 686 | 381 | 56 |
| NV Energy | 591 | 622 | (31) | (5) |
| Northern Powergrid | 300 | 266 | 34 | 13 |
| BHE Pipeline Group | 1,093 | 401 | 692 | * |
| BHE Transmission | 180 | 172 | 8 | 5 |
| BHE Renewables | 190 | 178 | 12 | 7 |
| HomeServices | 1,232 | 893 | 339 | 38 |
| BHE and Other | 186 | 103 | 83 | 81 |
| Total operating revenue | $ 6,081 | $ 4,527 | $ 1,554 | 34 % |
| | | | | |
| **(Loss) earnings on common shares:** | | | | |
| PacifiCorp | $ 169 | $ 176 | $ (7) | (4)% |
| MidAmerican Funding | 144 | 150 | (6) | (4) |
| NV Energy | 34 | 20 | 14 | 70 |
| Northern Powergrid | 104 | 87 | 17 | 20 |
| BHE Pipeline Group | 383 | 179 | 204 | * |
| BHE Transmission | 59 | 55 | 4 | 7 |
| BHE Renewables(1) | 16 | 95 | (79) | (83) |
| HomeServices | 84 | 10 | 74 | * |
| BHE and Other | (1,027) | (102) | (925) | * |
| (Loss) earnings on common shares | $ (34) | $ 670 | $ (704) | * |

(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 $704 million for the first quarter of 2021 compared to 2020. The first quarter of 2021 included a pre-tax unrealized loss of $1,124 million ($818 million after-tax) compared to a pre-tax unrealized gain in the first quarter of 2020 of $54 million ($39 million after-tax) on the Company's investment in BYD Company Limited. Excluding the impact of this item, adjusted earnings on common shares for the first quarter of 2021 was $784 million, an increase of $153 million, or 24%, compared to adjusted earnings on common shares in the first quarter of 2020 of $631 million.

The decrease in earnings on common shares for the first quarter of 2021 compared to 2020 was primarily due to the following:

- $204 million higher net income at BHE Pipeline Group, primarily due to $107 million of incremental net income from BHE GT&S, acquired in November 2020, higher gross margin on gas sales and higher transportation revenue at Northern Natural Gas, largely due to the favorable impact of the February 2021 polar vortex weather event, and the impacts of the 2020 rate case settlement at Northern Natural Gas;
- $79 million lower net income at BHE Renewables, primarily due to lower wind tax equity investment earnings from net losses on existing tax equity investments, largely due to the February 2021 polar vortex weather event, partially offset by increased income tax benefits from projects reaching commercial operation;

- $74 million higher net income at HomeServices, primarily due to higher earnings from mortgage services (63% increase in funded mortgage volume) and brokerage services (35% increase in closed transaction volume) largely attributable to the favorable interest rate environment; and
- $925 higher net loss at BHE and Other due to the $857 million unfavorable change in the after-tax unrealized position of the Company's investment in BYD Company Limited, $38 million of dividends on BHE's 4.00% Perpetual Preferred Stock issued to certain subsidiaries of Berkshire Hathaway in October 2020, higher BHE corporate interest expense from debt issuances in March and October 2020 and higher other corporate costs, partially offset by favorable changes in the cash surrender value of corporate-owned life insurance policies.

Reportable Segment Results

*PacifiCorp*

Operating revenue increased $36 million for the first quarter of 2021 compared to 2020, primarily due to higher retail revenue of $20 million and higher wholesale and other revenue of $16 million. Retail revenue increased due to higher customer volumes of $15 million and price impacts of $5 million from changes in sales mix, partially offset by lower rates due to certain general rate case orders. Retail customer volumes increased 0.3%, primarily due to an increase in the average number of customers and the favorable impact of weather, partially offset by lower customer usage. Wholesale and other revenue increased primarily due to higher wholesale volumes and higher average wholesale market prices.

Net income decreased $7 million for the first quarter of 2021 compared to 2020, primarily due to higher depreciation and amortization expense, including the impacts of a depreciation study effective in January 2021, lower allowances for equity and borrowed funds used during construction of $12 million and higher property taxes of $12 million, partially offset by higher utility margin of $29 million and favorable income tax expense from the impacts of ratemaking and higher PTCs recognized due to new wind-powered generating facilities placed in-service. Utility margin increased primarily due to the higher retail and wholesale revenue and lower purchased power costs, partially offset by higher natural gas-fueled and coal-fueled generation costs and higher net amortization of deferred net power costs in accordance with established adjustment mechanisms.

*MidAmerican Funding*

Operating revenue increased $381 million for the first quarter of 2021 compared to 2020, primarily due to higher natural gas operating revenue of $303 million and higher electric operating revenue of $74 million. Natural gas operating revenue increased due to a higher average per-unit cost of natural gas sold, primarily due to the February 2021 polar vortex weather event resulting in higher purchased gas adjustment recoveries of $304 million (offset in cost of sales). Electric operating revenue increased due to higher retail revenue of $40 million and higher wholesale and other revenue of $32 million mainly from higher wholesale volumes. Electric retail revenue increased primarily due to $32 million higher recoveries through the energy adjustment clauses (offset primarily in cost of sales), higher customer volumes of $5 million and price impacts of $5 million from changes in sales mix. Electric retail customer volumes increased 4.9% due to the favorable impact of weather and increased usage of certain industrial customers.

Net income decreased $6 million for the first quarter of 2021 compared to 2020, primarily due to higher depreciation and amortization expense of $31 million from additional assets placed in-service and the expiration of a regulatory mechanism deferring certain depreciation expense and $28 million higher operations and maintenance expenses, partially offset by a favorable income tax benefit and favorable changes in the cash surrender value of corporate-owned life insurance policies. Higher operations and maintenance expenses included increased costs associated with additional wind-powered generating facilities placed in-service as well as higher electric and natural gas distribution costs. The favorable income tax benefit was mainly due to higher PTCs recognized from higher wind-powered generation, driven primarily by new wind projects placed in-service, partially offset by the impacts of ratemaking. Electric utility margin increased $3 million as the higher retail and wholesale revenue was largely offset by higher generation and purchased power costs.

*NV Energy*

Operating revenue decreased $31 million for the first quarter of 2021 compared to 2020, primarily due to lower electric operating revenue of $22 million and lower natural gas operating revenue of $9 million. Electric operating revenue decreased primarily due to lower base tariff general rates of $14 million, lower retail customer volumes, lower fully-bundled energy rates (offset in cost of sales) of $4 million and price impacts from changes in sales mix. Electric retail customer volumes, including distribution only service customers, decreased 3.2%, primarily due to the impacts of COVID-19, which resulted in lower distribution only service, industrial and commercial customer usage and higher residential customer usage, partially offset by the favorable impact of weather. Natural gas operating revenue decreased due to a lower average per-unit cost of natural gas sold (offset in cost of sales).

Net income increased $14 million for the first quarter of 2021 compared to 2020, primarily due to lower operations and maintenance expense of $22 million, primarily from lower regulatory instructed deferrals and amortizations and lower plant operations and maintenance costs, favorable changes in the cash surrender value of corporate-owned life insurance policies, lower interest expense of $7 million and lower income tax expense from the impacts of ratemaking, partially offset by lower electric utility margin of $18 million and higher depreciation and amortization expense of $13 million, mainly from the regulatory amortization of decommissioning costs and higher plant placed in-service. Electric utility margin decreased primarily due to the lower base tariff general rates at Nevada Power, lower retail customer volumes and price impacts from changes in sales mix.

*Northern Powergrid*

Operating revenue increased $34 million for the first quarter of 2021 compared to 2020, primarily due to $21 million from the weaker United States dollar and higher distribution revenue of $13 million, mainly from increased tariff rates of $10 million. Net income increased $17 million for the first quarter of 2021 compared to 2020, primarily due to the higher distribution revenue and $7 million from the weaker United States dollar.

*BHE Pipeline Group*

Operating revenue increased $692 million for the first quarter of 2021 compared to 2020, primarily due to $559 million of incremental revenue at BHE GT&S, acquired in November 2020, higher gas sales at Northern Natural Gas of $91 million and higher transportation revenue of $33 million at Northern Natural Gas, largely due to the favorable impacts of the February 2021 polar vortex weather event. Net income increased $204 million for the first quarter of 2021 compared to 2020, primarily due to $107 million of incremental net income at BHE GT&S and higher earnings of $98 million at Northern Natural Gas. Northern Natural Gas' improved performance was primarily due to higher gross margin on gas sales of $75 million, higher transportation revenue and the impacts of the 2020 rate case settlement.

*BHE Transmission*

Operating revenue increased $8 million for the first quarter of 2021 compared to 2020, primarily due to $10 million from the stronger United States dollar and higher revenue from the Montana-Alberta Tie-Line, acquired in May 2020, partially offset by the impacts of a regulatory decision received in November 2020 at AltaLink. Net income increased $4 million for the first quarter of 2021 compared to 2020, primarily due to higher earnings from the Montana-Alberta Tie-Line and lower non-regulated interest expense at BHE Canada.

*BHE Renewables*

Operating revenue increased $12 million for the first quarter of 2021 compared to 2020, primarily due to higher hydro, geothermal and solar revenues from higher generation as well as favorable pricing at the geothermal facilities. Net income decreased $79 million for the first quarter 2021 compared to 2020, primarily due to lower wind tax equity investment earnings of $93 million, partially offset by the higher operating revenue. Wind tax equity investment earnings decreased due to unfavorable results from existing tax equity investments of $138 million, primarily due to the February 2021 polar vortex weather event, partially offset by increased income tax benefits from projects reaching commercial operation.

*HomeServices*

Operating revenue increased $339 million for the first quarter of 2021 compared to 2020, primarily due to higher brokerage revenue of $228 million from a 35% increase in closed transaction volume and higher mortgage revenue of $92 million from a 63% increase in funded mortgage volume due to an increase in refinance activity from the favorable interest rate environment. Net income increased $74 million for the first quarter of 2021 compared to 2020, primarily due to higher earnings from mortgage services of $36 million and brokerage services of $27 million largely attributable to the favorable interest rate environment.

*BHE and Other*

Operating revenue increased $83 million for the first quarter of 2021 compared to 2020, primarily due to higher electricity and natural gas sales revenue at MidAmerican Energy Services, LLC, from favorable pricing offset by lower volumes. Net loss increased $925 million for the first quarter of 2021 compared to 2020, primarily due to the $857 million unfavorable change in the after-tax unrealized position of the Company's investment in BYD Company Limited, $38 million of dividends on BHE's 4.00% Perpetual Preferred Stock issued to certain subsidiaries of Berkshire Hathaway in October 2020, higher BHE corporate interest expense from debt issuances in March and October 2020 and higher other corporate costs, partially offset by favorable changes in the cash surrender value of corporate-owned life insurance policies.

**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 the Company's Annual Report on Form 10-K for the year ended December 31, 2020 for further discussion regarding the limitation of distributions from BHE's subsidiaries.

As of March 31, 2021, the Company's total net liquidity was as follows (in millions):

| | BHE | PacifiCorp | MidAmerican Funding | NV Energy | Northern Powergrid | BHE Canada | Other | Total |
|---|---|---|---|---|---|---|---|---|
| Cash and cash equivalents | $ 418 | $ 43 | $ 38 | $ 103 | $ 83 | $ 71 | $ 520 | $ 1,276 |
| Credit facilities | 3,500 | 1,200 | 1,509 | 650 | 207 | 935 | 3,232 | 11,233 |
| Less: | | | | | | | | |
| Short-term debt | — | (95) | (387) | (55) | — | (218) | (1,944) | (2,699) |
| Tax-exempt bond support and letters of credit | — | (218) | (370) | — | — | (2) | — | (590) |
| Net credit facilities | 3,500 | 887 | 752 | 595 | 207 | 715 | 1,288 | 7,944 |
| Total net liquidity | $ 3,918 | $ 930 | $ 790 | $ 698 | $ 290 | $ 786 | $ 1,808 | $ 9,220 |
| Credit facilities: | | | | | | | | |
| Maturity dates | 2022 | 2022 | 2021, 2022 | 2022 | 2023 | 2021, 2024 | 2021, 2022 | |

Operating Activities

Net cash flows from operating activities for the three-month periods ended March 31, 2021 and 2020 were $1.5 billion and $1.2 billion, respectively. The increase was primarily due to improved operating results and favorable income tax cash flows, 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 and assumptions used for each payment date.

Investing Activities

Net cash flows from investing activities for the three-month periods ended March 31, 2021 and 2020 were $(1.4) billion and $(1.5) billion, respectively. The change was primarily due to lower funding of tax equity investments and lower capital expenditures of $61 million. Refer to "Future Uses of Cash" for further discussion of capital expenditures.

Financing Activities

Net cash flows from financing activities for the three-month period ended March 31, 2021 was $(191) million. Sources of cash totaled $409 million and consisted of net proceeds from short-term debt. Uses of cash totaled $600 million and consisted mainly of repayments of BHE senior debt totaling $450 million, distributions to noncontrolling interests of $115 million and repayments of subsidiary debt totaling $26 million.

For a discussion of recent financing transactions, refer to Note 5 of Notes to Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q.

Net cash flows from financing activities for the three-month period ended March 31, 2020 was $1.4 billion. Sources of cash totaled $4.3 billion and consisted of proceeds from BHE senior debt issuances totaling $3.2 billion and subsidiary debt issuances totaling $1.1 billion. Uses of cash totaled $3.0 billion and consisted mainly of repayments of subsidiary debt totaling $1.3 billion, net repayments of short-term debt totaling $1.1 billion, repayments of BHE senior debt totaling $350 million and common stock repurchases totaling $126 million.

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.

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, are as follows (in millions):

| | Three-Month Periods Ended March 31, 2020 | Three-Month Periods Ended March 31, 2021 | Annual Forecast 2021 |
|---|---|---|---|
| **Capital expenditures by business:** | | | |
| PacifiCorp | $ 366 | $ 439 | $ 1,897 |
| MidAmerican Funding | 472 | 298 | 2,200 |
| NV Energy | 163 | 167 | 854 |
| Northern Powergrid | 159 | 179 | 732 |
| BHE Pipeline Group | 120 | 102 | 1,204 |
| BHE Transmission | 56 | 77 | 279 |
| BHE Renewables | 12 | 18 | 95 |
| HomeServices | 7 | 8 | 39 |
| BHE and Other[(1)] | 1 | 7 | 78 |
| Total | $ 1,356 | $ 1,295 | $ 7,378 |
| **Capital expenditures by type:** | | | |
| Wind generation | $ 273 | $ 97 | $ 1,158 |
| Electric distribution | 365 | 427 | 1,849 |
| Electric transmission | 185 | 157 | 1,006 |
| Natural gas transmission and storage | 49 | 85 | 1,032 |
| Solar generation | — | 4 | 295 |
| Other | 484 | 525 | 2,038 |
| Total | $ 1,356 | $ 1,295 | $ 7,378 |

(1) BHE and Other represents amounts related principally to other entities, corporate functions and intersegment eliminations.

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

- Wind generation expenditures include the following:
    - Construction and acquisition of wind-powered generating facilities at MidAmerican Energy totaling $154 million for the three-month period ended March 31, 2020. MidAmerican Energy's forecast expenditures in 2021 for the construction of additional wind-powered generating facilities total $391 million and include 202 MWs of wind-powered generating facilities expected to be placed in-service in 2021.
    - Repowering of wind-powered generating facilities at MidAmerican Energy totaling $24 million and $6 million for the three-month periods ended March 31, 2021 and 2020, respectively. The repowering projects entail the replacement of significant components of older turbines. Planned spending for the repowered generating facilities totals $379 million for the remainder of 2021. MidAmerican Energy expects its repowered facilities to meet Internal Revenue Service 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 1,078 MWs of current repowering projects not in-service as of March 31, 2021, 80 MWs are currently expected to qualify for 100% of the federal PTCs available for 10 years following each facility's return to service, 591 MWs are expected to qualify for 80% of such credits and 407 MWs are expected to qualify for 60% of such credits.

    - Construction of wind-powered generating facilities at PacifiCorp totaling $27 million and $89 million for the three-month periods ended March 31, 2021 and 2020, respectively, and includes the 674 MWs of new wind-powered generating facilities that were placed in-service in 2020 and 516 MWs expected to be placed in-service in 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 once the equipment is placed in-service. PacifiCorp's 2019 IRP identified 1,920 MWs of new wind-powered generating resources that are expected to come online in 2024. PacifiCorp anticipates that the additional new wind-powered generation will be a mixture of owned and contracted resources. PacifiCorp anticipates costs associated with the construction of wind-powered generating facilities will total an additional $100 million for 2021.
    - Repowering existing wind-powered generating facilities at PacifiCorp totaling $5 million and $16 million for the three-month periods ended March 31, 2021 and 2020, respectively. The repowering projects entail the replacement of significant components of older turbines. Certain repowering projects were placed in service in 2019 and 2020 and the remaining repowering projects are expected to be placed in-service in 2021. The energy production from such repowered facilities is expected to qualify for 100% of the federal PTCs available for 10 years following each facility's return to service. Planned additional spending for certain existing wind-powered generating facilities totals $6 million for 2021.
    - Acquisition and repowering of wind-powered generating facilities at PacifiCorp totaling $1 million for the three-month period ended March 31, 2021. Planned additional spending for these wind-powered generating facilities totals $44 million for 2021.
- Electric distribution includes both growth and operating expenditures. Growth expenditures include new customer connections and enhancements to existing customer connections. Operating expenditures include ongoing distribution systems infrastructure needed at the Utilities and Northern Powergrid, wildfire mitigation, damage restoration and storm damage 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 PacifiCorp's costs for the 140-mile 500-kV Aeolus-Bridger/Anticline transmission line, which is a major segment of PacifiCorp's Energy Gateway Transmission expansion program, placed in-service in November 2020, the Nevada Utilities' Greenlink Nevada transmission expansion program and AltaLink's directly assigned projects from the Alberta Electric System Operator. Operating expenditures include 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, the Northern Natural Gas New Lisbon Expansion and Twin Cities Area Expansion projects. Operating expenditures include, among other items, asset modernization and pipeline integrity projects.
- Solar generation includes growth expenditures, including MidAmerican Energy's current plan for the construction of 117 MWs of small- and utility-scale solar generation during 2021, of which 37 MWs are expected to be placed in-service in 2021. Nevada Power's solar generation investment includes expenditures for a 150 MWs solar photovoltaic facility with an additional 100 MWs capacity of co-located battery storage, known as the Dry Lake generating facility. Commercial operation at Dry Lake is expected by the end of 2023.
- Other capital expenditures includes both growth and operating expenditures, including 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 coal combustion residuals.

*Other Renewable Investments*

The Company has invested in 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 no contributions for the three-month period ended March 31, 2021, and has commitments as of March 31, 2021, subject to satisfaction of certain specified conditions, to provide equity contributions of $616 million for the remainder of 2021 pursuant to these equity capital contribution agreements as the various projects achieve commercial operation. 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.

*Contractual Obligations*

As of March 31, 2021, there have been no material changes outside the normal course of business in contractual obligations from the information provided in Item 7 of the Company's Annual Report on Form 10-K for the year ended December 31, 2020 other than the recent financing transactions and renewable tax equity investments previously discussed.

**Quad Cities Generating Station Operating Status**

Exelon Generation Company, LLC ("Exelon Generation"), 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 zero emission credits ("ZECs") and recover the costs from certain ratepayers in Illinois, subject to certain limitations. The proceeds from the ZECs will provide Exelon Generation 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 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 expands the breadth and scope of the PJM's MOPR, which is effective as of the PJM's next capacity auction. While the FERC included some limited exemptions in its order, 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. On October 15, 2020, the FERC issued an order denying requests for rehearing of its April 16, 2020 order and accepting the PJM's two compliance filings, subject to a further compliance filing to revise minor aspects of the proposed MOPR methodology. As part of that order, the FERC also accepted the PJM's proposal to condense the schedule of activities leading up to the next capacity auction but did not specify when that schedule would commence given that a key element of the MOPR level computation remains pending before the FERC in another proceeding. In November 2020, the PJM announced that the next capacity auction will be conducted in May 2021.

On May 21, 2020, the FERC issued an order involving reforms to the PJM's day-ahead and real-time reserves markets that need to be reflected in the calculation of MOPR levels. In approving reforms to the PJM's reserves markets, the FERC also directed the PJM to develop a new methodology for estimating revenues that resources will receive for sales of energy and related services, which will then be used in calculating a number of parameters and assumptions used in the capacity market, including MOPR levels. The PJM submitted its new revenue projection methodology on August 5, 2020. On review of this compliance filing, the FERC is expected to address how these additional reforms will impact MOPR levels, the timeline for implementing the new revenue projection methodology, and the timing for commencing the capacity auction schedule.

Exelon Generation is currently working with the PJM and other stakeholders to pursue the FRR option as an alternative to the next PJM capacity auction. If Illinois implements the FRR option, Quad Cities Station could be removed from the PJM's capacity auction and instead supply capacity and be compensated under the FRR program. If Illinois cannot implement an FRR program in its PJM zones, then the MOPR will apply to Quad Cities Station, resulting in higher offers for its units that may not clear the capacity market. Implementing the FRR program in Illinois will require both legislative and regulatory changes. MidAmerican Energy cannot predict whether or when such legislative and regulatory changes can be implemented or their potential impact on the continued operation of Quad Cities Station.

## Regulatory Matters

BHE's regulated subsidiaries and certain affiliates are subject to comprehensive regulation. The discussion below contains material developments to those matters disclosed in Item 1 of each Registrant's Annual Report on Form 10-K for the year ended December 31, 2020 and new regulatory matters occurring in 2021.

### *PacifiCorp*

#### *Utah*

In March 2020, PacifiCorp filed its annual EBA application with the UPSC requesting recovery of $37 million of deferred 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.

#### *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 facilities, new wind facilities and certain other new investments that had not been placed in service at the time of the filing. Additional compliance filings will be made to include these investments in rates concurrent when they are placed in service. In January 2021, the OPUC approved the second compliance filing to add the remainder of the Ekola Flats wind 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 facility and the Pryor Mountain new wind facility to rates, resulting in a rate increase of $14 million, or 1.2%, effective April 9, 2021.

#### *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 is scheduled to occur in July 2021.

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 the 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. The WPSC decision is pending. PacifiCorp has requested a rate effective date of July 1, 2021.

In April 2021, PacifiCorp filed its annual ECAM and RRA 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 has requested an interim rate effective date of July 1, 2021.

*Idaho*

In March 2021, PacifiCorp filed its annual ECAM application with the IPUC requesting recovery of $14 million for deferred costs in 2020. 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, 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. This reflects a 1.1% decrease compared to current rates.

*California*

California Senate Bill 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.

*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 North American Electric Reliability Corporation (the "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. PacifiCorp will file a response to the allegations with the FERC.

*MidAmerican Energy*

*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 natural gas sales over the period April 2021 through April 2022. While sufficient liquidity is available to MidAmerican Energy, the increased costs and longer recovery period resulted in higher working capital requirements during the three-month period ended March 31, 2021.

*NV Energy (Nevada Power and Sierra Pacific)*

*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 that is based on renewable resources. The CPST provides for an energy rate that would replace the Base Tariff Energy Rate 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 tariff with the PUCN. An order is expected in the second quarter of 2021.

*Natural Disaster Protection Plan*

The Nevada Utilities submitted their initial natural disaster protection plan 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 minor adjustments to the budget and approved the 2019 costs for recovery starting in October 2020. In October 2020, intervening parties filed petitions for reconsideration. Intervenors have 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 natural disaster protection plan, as modified, and reopened its investigation and rulemaking on Senate Bill 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 the second quarter of 2021. In March 2021, the Nevada Utilities filed an application seeking recovery of the 2020 expenditures, approval for an update to the initial natural disaster protection plan that was ordered by the PUCN and filed their first amendment to the 2020 natural disaster protection plan.

*Northern Powergrid Distribution Companies*

In December 2020, GEMA, through Ofgem, published its final determinations for transmission and gas distribution networks in Great Britain. These determinations do not apply directly to Northern Powergrid, but aspects of the proposals are capable of application at Northern Powergrid's next price control, ("ED2"), which will begin in April 2023. Regarding allowed return on capital, Ofgem determined a cost of equity of 4.55% (plus inflation calculated using the United Kingdom's consumer price index including owner occupiers' housing costs ("CPIH")). In March 2021, all the transmission and gas distribution networks lodged appeals with the Competition and Markets Authority against Ofgem's determination for the cost of equity.

In December 2020, in respect of electricity distribution, GEMA published its decision on the methodology it will use to set the ED2 price control and prices from April 2023 to March 2028. This confirmed that Ofgem will apply many aspects of the proposals from the transmission and gas distribution price controls to electricity distribution.

GEMA published a separate decision in March 2021, confirming that the financial aspects in respect of electricity distribution would broadly follow the transmission and gas distribution methodology, setting a working assumption for a cost of equity at 4.65% (plus CPIH), ahead of the final determinations in late 2022. When placed on a comparable footing, by adjusting for differences in the assumed equity ratio and the measure of inflation used, the working assumption for ED2 is approximately 150 basis points lower than the current cost of equity.

*BHE Pipeline Group*

*BHE GT&S*

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, 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 $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.

*BHE Transmission*

*AltaLink*

*Tariff Refund Application*

In January 2021, driven by the pandemic and economic shutdown that has 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 consist of a proposed refund to customers of C$150 million of previously collected future income taxes and C$200 million of surplus accumulated depreciation. The future income tax refund would be evenly distributed over the two-year period, 2021 to 2022, with C$75 million included in each year. The accumulated depreciation surplus would be refunded over the three-year period, 2021 to 2023, with C$60 million included in 2021 and 2022, and C$80 million in 2023. If approved by the AUC, these tariff relief measures would have saved customers an estimated C$317 million over the three-year period, 2021 to 2023.

In March 2021, the AUC issued a decision on AltaLink's Tariff Refund Application and approved a 2021 tariff refund in the amount of C$230 million and a net 2021 tariff reduction of C$224 million, which provides Alberta ratepayers with immediate tariff relief in 2021. The approved 2021 tariff refund includes 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 will be 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. Excluded matters were examined by the AUC in a hearing held in November 2019, with written arguments filed in January 2020.

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 October 2020, AltaLink filed responses to information requests from the AUC, written argument was filed by intervening parties and written reply argument was filed by AltaLink. 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 continuing to transition to the AUC-approved salvage recovery method, continuing the use of the flow-through income tax method, and adding only a 1% increase to operations and maintenance expense, with the exception of salaries and wages and other expenses. 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 tariff of C$824 million and C$847 million for 2022 and 2023, respectively.

*2022 Generic Cost of Capital Proceeding*

In December 2020, the AUC initiated the 2022 generic cost of capital proceeding. This proceeding will consider the return on equity and deemed equity ratios for 2022 and one or more additional test years. Due to the existing uncertainty as a result of the ongoing COVID-19 pandemic, before establishing a process schedule, the commission has requested participants to submit comments that address 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 is 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 ratepayers.

In April 2021, the Utilities Consumer Advocate filed an application with the Court of Appeal of Alberta requesting permission to appeal the AUC's decision that set the return on equity of 8.5% and equity ratio of 37% on a final basis for 2022. In the appeal, the Utilities Consumer Advocate alleges that the AUC erred by failing to fulfil its statutory obligation of establishing a fair return and by failing to apply procedural fairness.

*2019 Deferral Accounts Reconciliation Application*

In October 2020, AltaLink filed its application with the AUC, which includes ten projects with total gross capital additions of C$129 million, including applicable AFUDC. In December 2020, AltaLink provided responses to AUC information requests, interveners filed written argument and AltaLink filed reply argument.

In March 2021, the AUC issued its decision on AltaLink's 2019 Deferral Accounts Reconciliation Application. The AUC approved C$128.0 million of the C$128.5 million of gross capital project additions, disallowing C$0.5 million of capital costs. 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.

**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 discussion below contains material developments to those matters disclosed in Item 1 of each Registrant's Annual Report on Form 10-K for the year ended December 31, 2020, and new environmental matters occurring in 2021.

*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; 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 April 22 through April 23, 2021, President Biden announced new climate goals to cut GHG 50%-52% economy-wide by 2030 compared to 2005 levels, and to reach 100% carbon pollution-free electricity by 2035. Additional details on how the United States will implement these goals is anticipated to be released through fall 2021.

*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 as described below.

*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-fired 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. 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, 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. 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 April 5, 2021, remanding it for further proceedings.

*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.

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 require 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.

*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, EPA finalized a rule to close out the CSAPR, having determined that the CSAPR Update for the 2008 ozone NAAQS fully addressed Clean Air Act interstate transport obligations of 20 eastern states. 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. 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 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 power plants 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 power plants 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 largely as proposed. Significant new compliance obligations are not anticipated as a result of the rule.

*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 controls at Hunter Units 1 and 2 and Huntington Units 1 and 2 within five years. 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 controls 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 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 plant enforceable under the SIP and removes the requirement to install SCR technology 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 plant federally enforceable and adopts as BART the existing $NO_x$ controls and emission limits on the Hunter and Huntington plants. The proposed approval withdraws the FIP requirements to install SCR 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 plants. 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, which has been stayed pending the Biden administration's review of the rule.

**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. Estimates are used for, but not limited to, the accounting for the effects of certain types of regulation, derivatives, impairment of goodwill and long-lived assets, pension and other postretirement benefits, income taxes and revenue recognition - unbilled revenue. For additional discussion of the Company's critical accounting estimates, see Item 7 of the Company's Annual Report on Form 10-K for the year ended December 31, 2020. There have been no significant changes in the Company's assumptions regarding critical accounting estimates since December 31, 2020.

## PacifiCorp and its subsidiaries
## Consolidated Financial Section

## PART I

**Item 1. Financial Statements**

### REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
PacifiCorp

**Results of Review of Interim Financial Information**

We have reviewed the accompanying consolidated balance sheet of PacifiCorp and subsidiaries ("PacifiCorp") as of March 31, 2021, the related consolidated statements of operations, changes in shareholders' equity and cash flows for the three-month periods ended March 31, 2021 and 2020, and the related notes (collectively referred to as the "interim financial information"). Based on our reviews, we are not aware of any material modifications that should be made to the accompanying interim financial information for it to be in conformity with accounting principles generally accepted in the United States of America.

We have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheet of PacifiCorp as of December 31, 2020, and the related consolidated statements of operations, comprehensive income, changes in shareholders' equity, and cash flows for the year then ended (not presented herein); and in our report dated February 26, 2021, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying consolidated balance sheet as of December 31, 2020, is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

**Basis for Review Results**

This interim financial information is the responsibility of PacifiCorp's management. We are a public accounting firm registered with the 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 reviews in accordance with standards of the PCAOB. A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the PCAOB, the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

/s/ Deloitte & Touche LLP

Portland, Oregon
April 30, 2021

**PACIFICORP AND SUBSIDIARIES**
**CONSOLIDATED BALANCE SHEETS (Unaudited)**
(Amounts in millions)

| | As of | |
|---|---|---|
| | March 31, 2021 | December 31, 2020 |
| **ASSETS** | | |
| **Current assets:** | | |
| Cash and cash equivalents | $ 43 | $ 13 |
| Trade receivables, net | 650 | 703 |
| Other receivables, net | 48 | 48 |
| Inventories | 475 | 482 |
| Regulatory assets | 107 | 116 |
| Prepaid expenses | 73 | 79 |
| Other current assets | 109 | 82 |
| Total current assets | 1,505 | 1,523 |
| | | |
| Property, plant and equipment, net | 22,535 | 22,430 |
| Regulatory assets | 1,279 | 1,279 |
| Other assets | 479 | 470 |
| | | |
| **Total assets** | $ 25,798 | $ 25,702 |

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

**PACIFICORP AND SUBSIDIARIES**
**CONSOLIDATED BALANCE SHEETS (Unaudited) (continued)**
(Amounts in millions)

| | As of | |
|---|---|---|
| | March 31, 2021 | December 31, 2020 |
| **LIABILITIES AND SHAREHOLDERS' EQUITY** | | |
| **Current liabilities:** | | |
| Accounts payable | $ 615 | $ 772 |
| Accrued interest | 114 | 127 |
| Accrued property, income and other taxes | 118 | 80 |
| Accrued employee expenses | 112 | 84 |
| Short-term debt | 95 | 93 |
| Current portion of long-term debt | 879 | 420 |
| Regulatory liabilities | 111 | 115 |
| Other current liabilities | 178 | 174 |
| Total current liabilities | 2,222 | 1,865 |
| | | |
| Long-term debt | 7,734 | 8,192 |
| Regulatory liabilities | 2,728 | 2,727 |
| Deferred income taxes | 2,666 | 2,627 |
| Other long-term liabilities | 1,106 | 1,118 |
| Total liabilities | 16,456 | 16,529 |
| | | |
| Commitments and contingencies (Note 8) | | |
| | | |
| **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 | 4,880 | 4,711 |
| Accumulated other comprehensive loss, net | (19) | (19) |
| Total shareholders' equity | 9,342 | 9,173 |
| | | |
| **Total liabilities and shareholders' equity** | $ 25,798 | $ 25,702 |

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

**PACIFICORP AND SUBSIDIARIES**
**CONSOLIDATED STATEMENTS OF OPERATIONS (Unaudited)**
(Amounts in millions)

| | Three-Month Periods Ended March 31, | |
|---|---|---|
| | **2021** | **2020** |
| **Operating revenue** | $ 1,242 | $ 1,206 |
| **Operating expenses:** | | |
| Cost of fuel and energy | 424 | 417 |
| Operations and maintenance | 259 | 254 |
| Depreciation and amortization | 264 | 252 |
| Property and other taxes | 61 | 49 |
| Total operating expenses | 1,008 | 972 |
| **Operating income** | 234 | 234 |
| **Other income (expense):** | | |
| Interest expense | (107) | (102) |
| Allowance for borrowed funds | 6 | 10 |
| Allowance for equity funds | 13 | 21 |
| Interest and dividend income | 6 | 3 |
| Other, net | 6 | (4) |
| Total other income (expense) | (76) | (72) |
| **Income before income tax benefit** | 158 | 162 |
| Income tax benefit | (11) | (14) |
| **Net income** | $ 169 | $ 176 |

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

**PACIFICORP AND SUBSIDIARIES**
**CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY (Unaudited)**
(Amounts in millions)

| | Preferred Stock | Common Stock | Additional Paid-in Capital | Retained Earnings | Accumulated Other Comprehensive Loss, Net | Total Shareholders' Equity |
|---|---|---|---|---|---|---|
| **Balance, December 31, 2019** | $ 2 | $ — | $ 4,479 | $ 3,972 | $ (16) | $ 8,437 |
| Net income | — | — | — | 176 | — | 176 |
| Other comprehensive income | — | — | — | — | 1 | 1 |
| **Balance, March 31, 2020** | $ 2 | $ — | $ 4,479 | $ 4,148 | $ (15) | $ 8,614 |
| | | | | | | |
| **Balance, December 31, 2020** | $ 2 | $ — | $ 4,479 | $ 4,711 | $ (19) | $ 9,173 |
| Net income | — | — | — | 169 | — | 169 |
| **Balance, March 31, 2021** | $ 2 | $ — | $ 4,479 | $ 4,880 | $ (19) | $ 9,342 |

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

**PACIFICORP AND SUBSIDIARIES**
**CONSOLIDATED STATEMENTS OF CASH FLOWS (Unaudited)**
(Amounts in millions)

| | Three-Month Periods Ended March 31, | |
|---|---|---|
| | **2021** | **2020** |
| **Cash flows from operating activities:** | | |
| Net income | $ 169 | $ 176 |
| Adjustments to reconcile net income to net cash flows from operating activities: | | |
| Depreciation and amortization | 264 | 252 |
| Allowance for equity funds | (13) | (21) |
| Changes in regulatory assets and liabilities | (4) | (16) |
| Deferred income taxes and amortization of investment tax credits | 13 | (30) |
| Other, net | (2) | 6 |
| Changes in other operating assets and liabilities: | | |
| Trade receivables, other receivables and other assets | 61 | 85 |
| Inventories | 7 | (26) |
| Derivative collateral, net | 7 | (1) |
| Prepaid expenses | 6 | (3) |
| Accrued property, income and other taxes, net | 12 | 18 |
| Accounts payable and other liabilities | (51) | (3) |
| Net cash flows from operating activities | 469 | 437 |
| | | |
| **Cash flows from investing activities:** | | |
| Capital expenditures | (439) | (366) |
| Other, net | (1) | 27 |
| Net cash flows from investing activities | (440) | (339) |
| | | |
| **Cash flows from financing activities:** | | |
| Net proceeds from (repayments of) short-term debt | 2 | (74) |
| Other, net | (1) | — |
| Net cash flows from financing activities | 1 | (74) |
| | | |
| **Net change in cash and cash equivalents and restricted cash and cash equivalents** | 30 | 24 |
| **Cash and cash equivalents and restricted cash and cash equivalents at beginning of period** | 19 | 36 |
| **Cash and cash equivalents and restricted cash and cash equivalents at end of period** | $ 49 | $ 60 |

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

**PACIFICORP AND SUBSIDIARIES**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**
**(Unaudited)**

## (1) General

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").

The unaudited Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") for interim financial information and the United States Securities and Exchange Commission's rules and regulations for Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all of the disclosures required by GAAP for annual financial statements. Management believes the unaudited Consolidated Financial Statements contain all adjustments (consisting only of normal recurring adjustments) considered necessary for the fair presentation of the unaudited Consolidated Financial Statements as of March 31, 2021 and for the three-month periods ended March 31, 2021 and 2020. The Consolidated Statements of Comprehensive Income have been omitted as net income materially equals comprehensive income for the three-month periods ended March 31, 2021 and 2020. The results of operations for the three-month periods ended March 31, 2021 and 2020 are not necessarily indicative of the results to be expected for the full year.

The preparation of the unaudited Consolidated Financial Statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the unaudited Consolidated Financial Statements and the reported amounts of revenue and expenses during the period. Actual results may differ from the estimates used in preparing the unaudited Consolidated Financial Statements. Note 2 of Notes to Consolidated Financial Statements included in PacifiCorp's Annual Report on Form 10-K for the year ended December 31, 2020 describes the most significant accounting policies used in the preparation of the unaudited Consolidated Financial Statements. There have been no significant changes in PacifiCorp's assumptions regarding significant accounting estimates and policies during the three-month period ended March 31, 2021.

## (2) 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 representing vendor retention, custodial and nuclear decommissioning funds. Restricted amounts are included in other current assets and other assets on the Consolidated Balance Sheets. A reconciliation of cash and cash equivalents and restricted cash and cash equivalents as of March 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 | |
|---|---|---|
| | March 31, 2021 | December 31, 2020 |
| Cash and cash equivalents | $ 43 | $ 13 |
| Restricted cash included in other current assets | 3 | 4 |
| Restricted cash included in other assets | 3 | 2 |
| Total cash and cash equivalents and restricted cash and cash equivalents | $ 49 | $ 19 |

## (3) Property, Plant and Equipment, Net

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

| | | As of | |
|---|---|---|---|
| | Depreciable Life | March 31, 2021 | December 31, 2020 |
| **Utility Plant:** | | | |
| Generation | 15 - 59 years | $ 13,355 | $ 12,861 |
| Transmission | 60 - 90 years | 7,686 | 7,632 |
| Distribution | 20 - 75 years | 7,725 | 7,660 |
| Intangible plant[(1)] | 5 - 75 years | 1,069 | 1,054 |
| Other | 5 - 60 years | 1,513 | 1,510 |
| Utility plant in service | | 31,348 | 30,717 |
| Accumulated depreciation and amortization | | (9,980) | (9,838) |
| Utility plant in service, net | | 21,368 | 20,879 |
| Other non-regulated, net of accumulated depreciation and amortization | 14 - 95 years | 9 | 9 |
| Plant, net | | 21,377 | 20,888 |
| Construction work-in-progress | | 1,158 | 1,542 |
| Property, plant and equipment, net | | $ 22,535 | $ 22,430 |

(1) Computer software costs included in intangible plant are initially assigned a depreciable life of 5 to 10 years.

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 $37 million for the three-month period ended March 31, 2021 compared to the three-month period ended March 31, 2020 based on historical property, plant and equipment balances and including depreciation of certain coal-fueled generating units in Washington over accelerated periods.

## (4) Income Taxes

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:

| | Three-Month Periods Ended March 31, | |
|---|---|---|
| | 2021 | 2020 |
| Federal statutory income tax rate | 21 % | 21 % |
| State income tax, net of federal income tax benefit | 3 | 3 |
| Federal income tax credits | (20) | (11) |
| Effects of ratemaking | (13) | (22) |
| Other | 2 | — |
| Effective income tax rate | (7)% | (9)% |

Income tax credits relate primarily to production tax credits ("PTCs") 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 for the three-month periods ended March 31, 2021 and 2020 is primarily attributable to the amortization of excess deferred income taxes, including the use of excess deferred income taxes of $3 million and $30 million, respectively, to accelerate depreciation of certain retired wind equipment and to amortize certain regulatory asset balances in accordance with regulatory orders issued in Oregon and Wyoming.

Berkshire Hathaway includes BHE and its subsidiaries in its United States federal income tax return. Consistent with established regulatory practice, PacifiCorp's provision for federal and state income tax has been computed on a stand-alone basis, and substantially all of its currently payable or receivable income tax is remitted to or received from BHE. For the three-month periods ended March 31, 2021 and 2020, PacifiCorp made net cash payments for federal and state income tax to BHE totaling $1 million and $26 million, respectively.

## (5) Employee Benefit Plans

Net periodic benefit credit for the pension and other postretirement benefit plans included the following components (in millions):

| | Three-Month Periods Ended March 31, | |
|---|---|---|
| | **2021** | **2020** |
| **Pension:** | | |
| Service cost | $ — | $ — |
| Interest cost | 7 | 9 |
| Expected return on plan assets | (13) | (14) |
| Net amortization | 5 | 5 |
| Net periodic benefit credit | $ (1) | $ — |
| | | |
| **Other postretirement:** | | |
| Service cost | $ — | $ — |
| Interest cost | 2 | 3 |
| Expected return on plan assets | (2) | (4) |
| Net amortization | — | — |
| Net periodic benefit credit | $ — | $ (1) |

Amounts other than the service cost for pension and other postretirement benefit plans are recorded in Other, net in the Consolidated Statements of Operations. Employer contributions to the pension and other postretirement benefit plans are expected to be $4 million and $1 million, respectively, during 2021. As of March 31, 2021, $1 million of contributions had been made to the pension plans.

## (6) 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, manage and report 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, 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 Note 7 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 March 31, 2021** | | | | | |
| **Not designated as hedging contracts[1]:** | | | | | |
| Commodity assets | $ 45 | $ 6 | $ 2 | $ — | $ 53 |
| Commodity liabilities | (2) | — | (27) | (24) | (53) |
| Total | 43 | 6 | (25) | (24) | — |
| | | | | | |
| Total derivatives | 43 | 6 | (25) | (24) | — |
| Cash collateral receivable | — | — | 13 | 4 | 17 |
| Total derivatives - net basis | $ 43 | $ 6 | $ (12) | $ (20) | $ 17 |
| | | | | | |
| **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 and as of March 31, 2021 and December 31, 2020, a regulatory asset of \$— million and \$17 million, respectively, was recorded related to the net derivative liability of \$— million and \$17 million, respectively.

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 (in millions):

| | Three-Month Periods Ended March 31, | |
|---|---|---|
| | 2021 | 2020 |
| **Beginning balance** | $ 17 | $ 62 |
| Changes in fair value | (17) | 34 |
| Net gains reclassified to operating revenue | — | 8 |
| Net losses reclassified to cost of fuel and energy | — | (20) |
| **Ending balance** | $ — | $ 84 |

*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 (in millions):

| | Unit of Measure | March 31, 2021 | December 31, 2020 |
|---|---|---|---|
| Electricity sales, net | Megawatt hours | — | (1) |
| Natural gas purchases | Decatherms | 114 | 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 March 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 $52 million and $51 million as of March 31, 2021 and December 31, 2020, respectively, for which PacifiCorp had posted collateral of $17 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 March 31, 2021 and December 31, 2020, PacifiCorp would have been required to post $30 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.

## (7) 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 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 March 31, 2021** | | | | | |
| **Assets:** | | | | | |
| Commodity derivatives | $ — | $ 53 | $ — | $ (4) | $ 49 |
| Money market mutual funds(2) | 36 | — | — | — | 36 |
| Investment funds | 30 | — | — | — | 30 |
| | $ 66 | $ 53 | $ — | $ (4) | $ 115 |
| **Liabilities - Commodity derivatives** | $ — | $ (53) | $ — | $ 21 | $ (32) |
| **As of December 31, 2020** | | | | | |
| **Assets:** | | | | | |
| Commodity derivatives | $ — | $ 36 | $ — | $ (3) | $ 33 |
| Money market mutual funds(2) | 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 $17 million and $24 million as of March 31, 2021 and December 31, 2020, respectively.

(2) Amounts are included in cash and cash equivalents, other current assets and other assets on the Consolidated Balance Sheets. The fair value of these money market mutual funds approximates cost.

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 6 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 (in millions):

| | As of March 31, 2021 | | As of December 31, 2020 | |
|---|---|---|---|---|
| | Carrying Value | Fair Value | Carrying Value | Fair Value |
| Long-term debt | $ 8,613 | $ 10,198 | $ 8,612 | $ 10,995 |

## (8) 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, including residences, destroyed; 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. 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.

As of March 31, 2021, 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 by January 16, 2021 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. On January 13, 2021, the new license transfer application was filed with the FERC, notifying it that PacifiCorp and the KRRC are not accepting co-licensee status under FERC's July 2020 order, and instead are seeking the license transfer outcome described in the new license transfer application. 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.

*Guarantees*

PacifiCorp 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 PacifiCorp's consolidated financial results.

## (9) Revenue from Contracts with Customers

The following table summarizes PacifiCorp's revenue from contracts with customers ("Customer Revenue") by customer class (in millions):

| | Three-Month Periods Ended March 31, 2021 | 2020 |
|---|---|---|
| Customer Revenue: | | |
| Retail: | | |
| Residential | $ 483 | $ 460 |
| Commercial | 359 | 358 |
| Industrial | 271 | 277 |
| Other retail | 32 | 27 |
| Total retail | 1,145 | 1,122 |
| Wholesale [1] | 36 | — |
| Transmission | 25 | 22 |
| Other Customer Revenue | 23 | 26 |
| Total Customer Revenue | 1,229 | 1,170 |
| Other revenue | 13 | 36 |
| Total operating revenue | $ 1,242 | $ 1,206 |

(1) Includes net payments to counterparties for the financial settlement of certain non-derivative forward contracts for energy sales.

## Item 2. 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 unaudited Consolidated Financial Statements and Notes to Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q. PacifiCorp's actual results in the future could differ significantly from the historical results.

### Results of Operations for the First Quarter of 2021 and 2020

Overview

Net income for the first three months of 2021 was $169 million, a decrease of $7 million compared to 2020. Net income decreased primarily due to lower allowances for equity and borrowed funds used during construction of $12 million, higher property taxes of $12 million, higher depreciation and amortization expense of $12 million, including the impacts of the depreciation study that was effective January 1, 2021, higher operations and maintenance expense of $5 million and higher interest expense of $5 million, partially offset by higher utility margin of $29 million and increased cash surrender value of corporate-owned life insurance policies. Utility margin increased primarily due to higher retail and wholesale revenue and lower purchased electricity costs, partially offset by higher natural gas-fueled generation costs, higher net amortization of deferred net power costs in accordance with established adjustment mechanisms, and higher coal-fueled generation costs. Retail customer volumes increased 0.3%, primarily due to an increase in the average number of customers across the service territory and favorable impact of weather, partially offset by lower customer usage. Energy generated increased 8% for the first three months of 2021 compared to 2020 primarily due to higher wind-powered, coal-fueled and natural gas-fueled generation, partially offset by lower hydroelectric generation. Wholesale electricity sales volumes increased 24% and purchased electricity volumes decreased 11%.

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 customers through regulatory recovery mechanisms and as a result, changes in PacifiCorp's revenue are comparable to changes in such expenses. 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 comparable financial measure prepared in accordance with GAAP. The following table provides a reconciliation of utility margin to operating income (in millions):

| | First Quarter | | | |
|---|---|---|---|---|
| | 2021 | 2020 | Change | |
| **Utility margin:** | | | | |
| Operating revenue | $ 1,242 | $ 1,206 | $ 36 | 3 % |
| Cost of fuel and energy | 424 | 417 | 7 | 2 |
| **Utility margin** | 818 | 789 | 29 | 4 |
| Operations and maintenance | 259 | 254 | 5 | 2 |
| Depreciation and amortization | 264 | 252 | 12 | 5 |
| Property and other taxes | 61 | 49 | 12 | 24 |
| **Operating income** | $ 234 | $ 234 | $ — | — % |

Utility Margin

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

| | First Quarter | | | |
|---|---|---|---|---|
| | 2021 | 2020 | Change | |
| **Utility margin (in millions):** | | | | |
| Operating revenue | $ 1,242 | $ 1,206 | $ 36 | 3 % |
| Cost of fuel and energy | 424 | 417 | 7 | 2 |
| Utility margin | $ 818 | $ 789 | $ 29 | 4 % |
| | | | | |
| **Sales (GWhs):** | | | | |
| Residential | 4,632 | 4,421 | 211 | 5 % |
| Commercial | 4,470 | 4,410 | 60 | 1 |
| Industrial, irrigation and other | 4,474 | 4,702 | (228) | (5) |
| Total retail | 13,576 | 13,533 | 43 | — |
| Wholesale | 1,591 | 1,281 | 310 | 24 |
| Total sales | 15,167 | 14,814 | 353 | 2 % |
| | | | | |
| **Average number of retail customers (in thousands)** | 1,989 | 1,955 | 34 | 2 % |
| | | | | |
| **Average revenue per MWh:** | | | | |
| Retail | $ 84.15 | $ 82.97 | $ 1.18 | 1 % |
| Wholesale | $ 30.89 | $ 26.35 | $ 4.54 | 17 % |
| | | | | |
| **Heating degree days** | 4,687 | 4,605 | 82 | 2 % |
| | | | | |
| **Sources of energy (GWhs)(1):** | | | | |
| Coal | 7,644 | 7,228 | 416 | 6 % |
| Natural gas | 3,065 | 3,041 | 24 | 1 |
| Hydroelectric(2) | 923 | 1,046 | (123) | (12) |
| Wind and other(2) | 1,803 | 1,112 | 691 | 62 |
| Total energy generated | 13,435 | 12,427 | 1,008 | 8 |
| Energy purchased | 3,028 | 3,391 | (363) | (11) |
| Total | 16,463 | 15,818 | 645 | 4 % |
| | | | | |
| **Average cost of energy per MWh:** | | | | |
| Energy generated(3) | $ 17.66 | $ 17.80 | $ (0.14) | (1)% |
| Energy purchased | $ 47.13 | $ 47.41 | $ (0.28) | (1)% |

(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.

Quarter Ended March 31, 2021 Compared to Quarter Ended March 31, 2020

*Utility margin* increased $29 million, or 4%, for the first quarter of 2021 compared to 2020 primarily due to:

- $20 million increase in retail revenue primarily due to higher customer volumes and higher average rates from sales mix, partially offset by lower prices due to certain general rate case orders. Retail customer volumes increased 0.3%, primarily due to an increase in the average number of customers across the service territory and favorable impact of weather, partially offset by lower customer usage;
- $18 million of lower purchased electricity costs from lower market prices and lower purchased volumes, partially due to higher wind generation from new Energy Vision 2020 ("EV 2020") generation and repowered facilities; and
- $15 million of higher wholesale revenue due to higher wholesale volumes and higher average wholesale market prices.

The increases above were partially offset by:

- $12 million of higher natural gas-fueled generation costs primarily due to higher average prices;
- $8 million primarily from higher net amortization of deferred net power costs in accordance with established adjustment mechanisms; and
- $6 million of higher coal-fueled generation costs primarily due to higher volumes, partially offset by lower average prices.

*Operations and maintenance* increased $5 million, or 2%, for the first quarter of 2021 compared to 2020 primarily due to higher vegetation management costs of $14 million, partially offset by cost savings from the retirement of Cholla unit 4 in December 2020 and decreased bad debt expense.

*Depreciation and amortization* increased $12 million, or 5%, for the first quarter of 2021 compared to 2020 primarily due to the impacts of a new depreciation study effective January 1, 2021 of approximately $37 million, including accelerated depreciation on coal-fueled units in Washington and an increase in assets placed in service, partially offset by a $44 million decrease resulting from lower accelerated depreciation for Oregon's share of certain retired wind equipment due to repowering ($3 million in the current quarter (fully offset in other revenue) compared to $47 million in the first quarter of 2020 ($7 million offset in other revenue and $40 million offset in income tax expense)).

*Property and other taxes* increased $12 million, or 24%, for the first quarter of 2021 compared to 2020 primarily due to higher property taxes from higher assessed property values.

*Interest expense* increased $5 million, or 5%, for the first quarter of 2021 compared to 2020 primarily due to a higher average long-term debt balance.

*Allowance for borrowed and equity funds* decreased $12 million, or 39%, for the first quarter of 2021 compared to 2020 primarily due to lower qualified construction work-in-progress balances due to large EV 2020 projects being placed in service.

*Other, net* increased $10 million from a loss of $4 million for the first quarter of 2020 to income of $6 million for the first quarter of 2021, primarily due to market movements related to corporate-owned life insurance policies.

*Income tax benefit* decreased $3 million, or 21%, for the first quarter of 2021 compared to the first quarter of 2020. The effective tax rate was (7)% for 2021 and (9)% for 2020. The effective tax rate increased primarily as a result of lower amortization of excess deferred income taxes in the current year, partially offset by increased PTCs from PacifiCorp's new wind-powered generating facilities. For the first quarter of 2021, $3 million of excess deferred income taxes was amortized pursuant to regulatory orders for Wyoming, whereby portions of excess deferred income taxes were used to offset certain regulatory balances for Wyoming. For the first quarter of 2020, $30 million of excess deferred income taxes was amortized pursuant to the Oregon RAC settlement, whereby a portion of excess deferred income taxes was used to accelerate depreciation for Oregon's share of certain retired wind equipment.

**Liquidity and Capital Resources**

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

| | |
|---|---|
| Cash and cash equivalents | $ 43 |
| | |
| Credit facilities | 1,200 |
| Less: | |
| Short-term debt | (95) |
| Tax-exempt bond support | (218) |
| Net credit facilities | 887 |
| | |
| Total net liquidity | $ 930 |
| | |
| Credit facilities: | |
| Maturity dates | 2022 |

Operating Activities

Net cash flows from operating activities for the three-month periods ended March 31, 2021 and 2020 were $469 million and $437 million, respectively. The change was primarily due to lower cash paid for income taxes, lower purchased power prices and volumes and lower fuel expense payments due to timing, partially offset by higher operating expense payments due to timing and higher cash paid for interest.

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 and assumptions for each payment date.

Investing Activities

Net cash flows from investing activities for the three-month periods ended March 31, 2021 and 2020 were $(440) million and $(339) million, respectively. The change is primarily due to an increase in capital expenditures of $73 million and prior year proceeds from the settlement of notes receivable of $25 million associated with the sale of certain Utah mining assets in 2015. Refer to "Future Uses of Cash" for discussion of capital expenditures.

Financing Activities

Net cash flows from financing activities for the three-month period ended March 31, 2021 was $1 million. Sources of cash consisted of $2 million from the borrowing of short-term debt.

Net cash flows from financing activities for the three-month period ended March 31, 2020 was $(74) million. Uses of cash consisted of $74 million for the repayment of short-term debt.

*Short-term Debt*

Regulatory authorities limit PacifiCorp to $1.5 billion of short-term debt. As of March 31, 2021, PacifiCorp had $95 million of short-term debt outstanding at a weighted average interest rate of 0.16%. As of December 31, 2020, PacifiCorp had $93 million of short-term debt outstanding at a weighted average interest rate of 0.16%.

*Debt Authorizations*

PacifiCorp currently has regulatory authority from the OPUC and the IPUC to issue an additional $3 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.

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 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, are as follows (in millions):

| | Three-Month Periods Ended March 31, | | Annual Forecast |
|---|---|---|---|
| | **2020** | **2021** | **2021** |
| Wind generation | $ 106 | $ 33 | $ 193 |
| Electric distribution | 99 | 195 | 730 |
| Electric transmission | 92 | 60 | 426 |
| Other | 69 | 151 | 548 |
| Total | $ 366 | $ 439 | $ 1,897 |

PacifiCorp's 2019 IRP identified a significant increase in renewable resource generation and associated transmission. PacifiCorp has included an estimate of the 2019 IRP resources in its forecast capital expenditures for 2021 through 2023. 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 totaling $27 million and $89 million for the three-month periods ended March 31, 2021 and 2020, respectively. Construction includes 674 MWs of new wind-powered generating facilities that were placed in-service in 2020 and 516 MWs expected to be placed in-service in 2021. The energy production for these new facilities is expected to qualify for 100% of the federal PTCs available for 10 years once the equipment is placed in-service. PacifiCorp's 2019 IRP identified 1,920 MWs of new wind-powered generating resources that are expected to come online in 2024. PacifiCorp anticipates that the additional new wind-powered generation will be a mixture of owned and contracted resources. PacifiCorp anticipates costs associated with the construction of wind-powered generating facilities will total an additional $100 million for 2021.
    - Repowering existing wind-powered generating facilities at PacifiCorp totaling $5 million and $16 million for the three-month periods ended March 31, 2021 and 2020, respectively. Certain repowering projects were placed in service in 2019 and 2020 with the remaining repowering projects expected to be placed in-service in 2021. The energy production from such repowered facilities is expected to qualify for 100% of the federal renewable electricity PTCs available for 10 years following each facility's return to service. Planned additional spending for certain existing wind-powered generating facilities totals $6 million for 2021.
    - Acquisition and repowering of wind-powered generating facilities totals $1 million for the three-month period ended March 31, 2021. Planned additional spending for these wind-powered generating facilities totals $44 million for 2021.

- Electric distribution includes both growth projects and operating expenditures. Operating expenditures includes planned spend on wildfire mitigation, wildfire damage restoration and storm damage repairs. Expenditures for these items totaled $83 million and $4 million for the three-month periods ended March 31, 2021 and 2020, respectively. PacifiCorp anticipates costs associated with these activities will total an additional $145 million in 2021. Remaining investments relate to expenditures for new connections and distribution.

- Electric transmission includes both growth projects and operating expenditures. Transmission investment through 2020 primarily reflects costs for the 140-mile 500-kV Aeolus-Bridger/Anticline transmission line, a major segment of PacifiCorp's Energy Gateway Transmission expansion program, placed in-service in November 2020. Planned spending for the additional Energy Gateway Transmission segments totals $182 million in 2021 and are expected to be placed in service in 2023 - 2024.

- Other includes both growth projects and operating expenditures. Expenditures for information technology totaled $13 million and $10 million for the three-month periods ended March 31, 2021 and 2020, respectively. PacifiCorp anticipates costs associated with information technology will total an additional $118 million for 2021. Remaining investments relate to operating projects that consist of routine expenditures for generation and other infrastructure needed to serve existing and expected demand.

*Requests for Proposals*

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

PacifiCorp 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 will be identified by June 2021.

*Contractual Obligations*

As of March 31, 2021, there have been no material changes outside the normal course of business in contractual obligations from the information provided in Item 7 of PacifiCorp's Annual Report on Form 10-K for the year ended December 31, 2020.

**Regulatory Matters**

PacifiCorp is subject to comprehensive regulation. Refer to "Regulatory Matters" in Berkshire Hathaway Energy's Part I, Item 2 of this Form 10-Q for discussion regarding PacifiCorp's 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 Berkshire Hathaway Energy's Part I, Item 2 of this Form 10-Q for additional information regarding environmental laws and regulations.

**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. Estimates are used for, but not limited to, the accounting for the effects of certain types of regulation, derivatives, pension and other postretirement benefits, income taxes and revenue recognition-unbilled revenue. For additional discussion of PacifiCorp's critical accounting estimates, see Item 7 of PacifiCorp's Annual Report on Form 10-K for the year ended December 31, 2020. There have been no significant changes in PacifiCorp's assumptions regarding critical accounting estimates since December 31, 2020.

**MidAmerican Funding, LLC and its subsidiaries and MidAmerican Energy Company**
**Consolidated Financial Section**

**PART I**

**Item 1. Financial Statements**

## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
MidAmerican Energy Company

**Results of Review of Interim Financial Information**

We have reviewed the accompanying balance sheet of MidAmerican Energy Company ("MidAmerican Energy") as of March 31, 2021, the related statements of operations, changes in shareholder's equity, and cash flows for the three-month periods ended March 31, 2021 and 2020, and the related notes (collectively referred to as the "interim financial information"). Based on our reviews, we are not aware of any material modifications that should be made to the accompanying interim financial information for it to be in conformity with accounting principles generally accepted in the United States of America.

We have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the balance sheet of MidAmerican Energy as of December 31, 2020, and the related statements of operations, changes in shareholder's equity, and cash flows for the year then ended (not presented herein); and in our report dated February 26, 2021, we expressed an unqualified opinion on those financial statements. In our opinion, the information set forth in the accompanying balance sheet as of December 31, 2020, is fairly stated, in all material respects, in relation to the balance sheet from which it has been derived.

**Basis for Review Results**

This interim financial information is the responsibility of MidAmerican Energy's management. We are a public accounting firm registered with the 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 reviews in accordance with standards of the PCAOB. A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the PCAOB, the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
April 30, 2021

**MIDAMERICAN ENERGY COMPANY**
**BALANCE SHEETS (Unaudited)**
(Amounts in millions)

| | As of | |
|---|---|---|
| | **March 31, 2021** | **December 31, 2020** |
| **ASSETS** | | |
| **Current assets:** | | |
| Cash and cash equivalents | $ 37 | $ 38 |
| Trade receivables, net | 521 | 234 |
| Income tax receivable | 293 | — |
| Inventories | 231 | 278 |
| Other current assets | 103 | 73 |
| Total current assets | 1,185 | 623 |
| | | |
| Property, plant and equipment, net | 19,223 | 19,279 |
| Regulatory assets | 439 | 392 |
| Investments and restricted investments | 938 | 911 |
| Other assets | 215 | 232 |
| | | |
| **Total assets** | $ 22,000 | $ 21,437 |

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

**MIDAMERICAN ENERGY COMPANY**
**BALANCE SHEETS (Unaudited) (continued)**
(Amounts in millions)

| | As of | |
|---|---|---|
| | March 31, 2021 | December 31, 2020 |
| **LIABILITIES AND SHAREHOLDER'S EQUITY** | | |
| **Current liabilities:** | | |
| Accounts payable | $ 292 | $ 408 |
| Accrued interest | 86 | 78 |
| Accrued property, income and other taxes | 124 | 161 |
| Short-term debt | 387 | — |
| Other current liabilities | 186 | 183 |
| Total current liabilities | 1,075 | 830 |
| | | |
| Long-term debt | 7,224 | 7,210 |
| Regulatory liabilities | 1,257 | 1,111 |
| Deferred income taxes | 3,107 | 3,054 |
| Asset retirement obligations | 711 | 709 |
| Other long-term liabilities | 414 | 458 |
| Total liabilities | 13,788 | 13,372 |
| | | |
| Commitments and contingencies (Note 8) | | |
| | | |
| **Shareholder's equity:** | | |
| Common stock - 350 shares authorized, no par value, 71 shares issued and outstanding | — | — |
| Additional paid-in capital | 561 | 561 |
| Retained earnings | 7,651 | 7,504 |
| Total shareholder's equity | 8,212 | 8,065 |
| | | |
| **Total liabilities and shareholder's equity** | $ 22,000 | $ 21,437 |

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

**MIDAMERICAN ENERGY COMPANY**
**STATEMENTS OF OPERATIONS (Unaudited)**
(Amounts in millions)

| | Three-Month Periods Ended March 31, | |
|---|---|---|
| | **2021** | **2020** |
| **Operating revenue:** | | |
| Regulated electric | $ 545 | $ 471 |
| Regulated natural gas and other | 522 | 210 |
| Total operating revenue | 1,067 | 681 |
| | | |
| **Operating expenses:** | | |
| Cost of fuel and energy | 151 | 80 |
| Cost of natural gas purchased for resale and other | 432 | 128 |
| Operations and maintenance | 193 | 165 |
| Depreciation and amortization | 207 | 176 |
| Property and other taxes | 36 | 34 |
| Total operating expenses | 1,019 | 583 |
| | | |
| **Operating income** | 48 | 98 |
| | | |
| **Other income (expense):** | | |
| Interest expense | (74) | (76) |
| Allowance for borrowed funds | 2 | 3 |
| Allowance for equity funds | 6 | 8 |
| Other, net | 11 | (5) |
| Total other income (expense) | (55) | (70) |
| | | |
| **(Loss) income before income tax benefit** | (7) | 28 |
| Income tax benefit | (154) | (123) |
| | | |
| **Net income** | $ 147 | $ 151 |

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

**MIDAMERICAN ENERGY COMPANY**
**STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY (Unaudited)**
(Amounts in millions)

| | Common Stock | Additional Paid-in Capital | Retained Earnings | Total Shareholder's Equity |
|---|---|---|---|---|
| **Balance, December 31, 2019** | $ — | $ 561 | $ 6,679 | $ 7,240 |
| Net income | — | — | 151 | 151 |
| **Balance, March 31, 2020** | $ — | $ 561 | $ 6,830 | $ 7,391 |
| | | | | |
| **Balance, December 31, 2020** | $ — | $ 561 | $ 7,504 | $ 8,065 |
| Net income | — | — | 147 | 147 |
| **Balance, March 31, 2021** | $ — | $ 561 | $ 7,651 | $ 8,212 |

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

**MIDAMERICAN ENERGY COMPANY**
**STATEMENTS OF CASH FLOWS (Unaudited)**
(Amounts in millions)

| | Three-Month Periods Ended March 31, | |
|---|---|---|
| | 2021 | 2020 |
| **Cash flows from operating activities:** | | |
| Net income | $ 147 | $ 151 |
| Adjustments to reconcile net income to net cash flows from operating activities: | | |
| Depreciation and amortization | 207 | 176 |
| Amortization of utility plant to other operating expenses | 8 | 9 |
| Allowance for equity funds | (6) | (8) |
| Deferred income taxes and amortization of investment tax credits | 154 | 91 |
| Settlements of asset retirement obligations | (4) | (2) |
| Other, net | (4) | 14 |
| Changes in other operating assets and liabilities: | | |
| Trade receivables and other assets | (299) | 15 |
| Inventories | 46 | (6) |
| Derivative collateral, net | (14) | 1 |
| Pension and other postretirement benefit plans | 1 | (6) |
| Accrued property, income and other taxes, net | (331) | (286) |
| Accounts payable and other liabilities | 10 | 70 |
| Net cash flows from operating activities | (85) | 219 |
| | | |
| **Cash flows from investing activities:** | | |
| Capital expenditures | (298) | (472) |
| Purchases of marketable securities | (52) | (127) |
| Proceeds from sales of marketable securities | 47 | 124 |
| Other, net | — | 5 |
| Net cash flows from investing activities | (303) | (470) |
| | | |
| **Cash flows from financing activities:** | | |
| Net proceeds from short-term debt | 387 | 50 |
| Other, net | — | (1) |
| Net cash flows from financing activities | 387 | 49 |
| | | |
| **Net change in cash and cash equivalents and restricted cash and cash equivalents** | (1) | (202) |
| **Cash and cash equivalents and restricted cash and cash equivalents at beginning of period** | 45 | 330 |
| **Cash and cash equivalents and restricted cash and cash equivalents at end of period** | $ 44 | $ 128 |

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

**MIDAMERICAN ENERGY COMPANY**
**NOTES TO FINANCIAL STATEMENTS**
**(Unaudited)**

## (1) General

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").

The unaudited Financial Statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") for interim financial information and the United States Securities and Exchange Commission's rules and regulations for Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all of the disclosures required by GAAP for annual financial statements. Management believes the unaudited Financial Statements contain all adjustments (consisting only of normal recurring adjustments) considered necessary for the fair presentation of the unaudited Financial Statements as of March 31, 2021, and for the three-month periods ended March 31, 2021 and 2020. The Statements of Comprehensive Income have been omitted as net income equals comprehensive income for the three-month period ended March 31, 2021 and 2020. The results of operations for the three-month periods ended March 31, 2021, are not necessarily indicative of the results to be expected for the full year.

The preparation of the unaudited Financial Statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the unaudited Financial Statements and the reported amounts of revenue and expenses during the period. Actual results may differ from the estimates used in preparing the unaudited Financial Statements. Note 2 of Notes to Financial Statements included in MidAmerican Energy's Annual Report on Form 10-K for the year ended December 31, 2020, describes the most significant accounting policies used in the preparation of the unaudited Financial Statements. There have been no significant changes in MidAmerican Energy's assumptions regarding significant accounting estimates and policies during the three-month period ended March 31, 2021.

## (2) 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 March 31, 2021 and December 31, 2020, consist substantially of funds restricted for wildlife preservation and, as of December 31, 2020, the purpose of constructing solid waste facilities under tax-exempt bond obligation agreements. A reconciliation of cash and cash equivalents and restricted cash and cash equivalents as of March 31, 2021 and December 31, 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 | |
|---|---|---|
| | **March 31, 2021** | **December 31, 2020** |
| Cash and cash equivalents | $ 37 | $ 38 |
| Restricted cash and cash equivalents in other current assets | 7 | 7 |
| Total cash and cash equivalents and restricted cash and cash equivalents | $ 44 | $ 45 |

## (3) Property, Plant and Equipment, Net

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

| | | As of | |
|---|---|---|---|
| | Depreciable Life | March 31, 2021 | December 31, 2020 |
| Utility plant in service, net: | | | |
| Generation | 20-70 years | $ 17,083 | $ 16,980 |
| Transmission | 52-75 years | 2,372 | 2,365 |
| Electric distribution | 20-75 years | 4,433 | 4,369 |
| Natural gas distribution | 29-75 years | 1,970 | 1,955 |
| Utility plant in service | | 25,858 | 25,669 |
| Accumulated depreciation and amortization | | (7,061) | (6,902) |
| Utility plant in service, net | | 18,797 | 18,767 |
| Nonregulated property, net: | | | |
| Nonregulated property gross | 20-50 years | 7 | 7 |
| Accumulated depreciation and amortization | | (1) | (1) |
| Nonregulated property, net | | 6 | 6 |
| | | 18,803 | 18,773 |
| Construction work-in-progress | | 420 | 506 |
| Property, plant and equipment, net | | $ 19,223 | $ 19,279 |

## (4) Regulatory Matters

*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 customers, the Iowa Utilities Board ordered the recovery of these higher costs to be applied to natural gas sales over the period April 2021 through April 2022. While sufficient liquidity is available to MidAmerican Energy, the increased costs and longer recovery period resulted in higher working capital requirements during three-month period ended March 31, 2021.

## (5) Income Taxes

The effective income tax rate for the three-month period ended March 31, 2021, is 2,200% and results from a $154 million income tax benefit associated with a $7 million pre-tax loss. The $154 million income tax benefit is primarily comprised of a $2 million benefit (21%) from the application of the statutory income tax rate to the pre-tax loss and a $168 million benefit (2,400%) from income tax credits, partially offset by a $13 million expense (186%) from the effects of ratemaking.

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:

| | Three-Month Periods Ended March 31, | |
|---|---|---|
| | **2021** | **2020** |
| Federal statutory income tax rate | 21 % | 21 % |
| Income tax credits | 2,400 | (430) |
| State income tax, net of federal income tax impacts | (29) | (28) |
| Effects of ratemaking | (186) | (3) |
| Other, net | (6) | 1 |
| Effective income tax rate | 2,200 % | (439)% |

Income tax credits relate primarily to production tax credits ("PTCs") from 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. MidAmerican Energy recognizes its renewable electricity PTCs throughout the year based on when the credits are earned and excludes them from the annual effective tax rate that is the basis for the interim recognition of other income tax expense. 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 three-month periods ended March 31, 2021 and 2020 totaled $151 million and $120 million, respectively.

Berkshire Hathaway includes BHE and subsidiaries in its United States federal and Iowa state income tax returns. Consistent with established regulatory practice, MidAmerican Energy's provision for income tax has been computed on a stand-alone basis, and substantially all of its currently payable or receivable income tax is remitted to or received from BHE. 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 and assumptions for each payment date. MidAmerican Energy made no cash payments for income tax to BHE for the three-month period ended March 31, 2021, and made net cash payments for income tax to BHE totaling $46 million for the three-month period ended March 31, 2020.

## (6) Employee Benefit Plans

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. 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.

Net periodic benefit cost (credit) for the plans of MidAmerican Energy and the aforementioned affiliates included the following components (in millions):

| | Three-Month Periods Ended March 31, 2021 | Three-Month Periods Ended March 31, 2020 |
|---|---|---|
| **Pension:** | | |
| Service cost | $ 5 | $ 1 |
| Interest cost | 6 | 6 |
| Expected return on plan assets | (9) | (10) |
| Net periodic benefit cost (credit) | $ 2 | $ (3) |
| | | |
| **Other postretirement:** | | |
| Service cost | $ 2 | $ 1 |
| Interest cost | 2 | 2 |
| Expected return on plan assets | (2) | (3) |
| Net amortization | (1) | (1) |
| Net periodic benefit cost (credit) | $ 1 | $ (1) |

Amounts other than the service cost for pension and other postretirement benefit plans are recorded in Other, net in the Statements of Operations. Employer contributions to the pension and other postretirement benefit plans are expected to be $7 million and $12 million, respectively, during 2021. As of March 31, 2021, $2 million and $3 million of contributions had been made to the pension and other postretirement benefit plans, respectively.

## (7) 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 March 31, 2021:** | | | | | |
| **Assets:** | | | | | |
| Commodity derivatives | $ — | $ 3 | $ 2 | $ (2) | $ 3 |
| Money market mutual funds(2) | 38 | — | — | — | 38 |
| Debt securities: | | | | | |
| United States government obligations | 210 | — | — | — | 210 |
| International government obligations | — | 5 | — | — | 5 |
| Corporate obligations | — | 71 | — | — | 71 |
| Municipal obligations | — | 2 | — | — | 2 |
| Agency, asset and mortgage-backed obligations | — | 5 | — | — | 5 |
| Equity securities: | | | | | |
| United States companies | 395 | — | — | — | 395 |
| International companies | 8 | — | — | — | 8 |
| Investment funds | 24 | — | — | — | 24 |
| | $ 675 | $ 86 | $ 2 | $ (2) | $ 761 |
| | | | | | |
| **Liabilities - commodity derivatives** | $ — | $ (1) | $ (1) | $ 2 | $ — |

| | Input Levels for Fair Value Measurements | | | | |
|---|---|---|---|---|---|
| | **Level 1** | **Level 2** | **Level 3** | **Other(1)** | **Total** |
| **As of December 31, 2020:** | | | | | |
| **Assets:** | | | | | |
| Commodity derivatives | $ — | $ 4 | $ 5 | $ (5) | $ 4 |
| Money market mutual funds(2) | 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 $— million as of March 31, 2021 and December 31, 2020, respectively.

(2) Amounts are included in cash and cash equivalents and investments and restricted investments on the Balance Sheets. The fair value of these money market mutual funds approximates cost.

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 Balance Sheets. 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 (in millions):

| | As of March 31, 2021 | | As of December 31, 2020 | |
|---|---|---|---|---|
| | Carrying Value | Fair Value | Carrying Value | Fair Value |
| Long-term debt | $ 7,224 | $ 8,305 | $ 7,210 | $ 9,130 |

## (8) Commitments and Contingencies

*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.

*Environmental Laws and Regulations*

MidAmerican Energy is subject to federal, state and local 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 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 Federal Energy Regulatory Commission ("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 a 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 March 31, 2021, has accrued a $10 million liability for refunds of amounts collected under the higher ROE during the periods covered by both complaints.

## (9) Revenue from Contracts with Customers

The following table summarizes MidAmerican Energy's revenue from contracts with customers ("Customer Revenue") by line of business and customer class, including a reconciliation to MidAmerican Energy's reportable segment information included in Note 10, (in millions):

| | For the Three-Month Period Ended March 31, 2021 | | | |
|---|---|---|---|---|
| | Electric | Natural Gas | Other | Total |
| Customer Revenue: | | | | |
| Retail: | | | | |
| Residential | $ 161 | $ 308 | $ — | $ 469 |
| Commercial | 71 | 129 | — | 200 |
| Industrial | 190 | 12 | — | 202 |
| Natural gas transportation services | — | 10 | — | 10 |
| Other retail[1] | 30 | 1 | — | 31 |
| Total retail | 452 | 460 | — | 912 |
| Wholesale | 74 | 51 | — | 125 |
| Multi-value transmission projects | 15 | — | — | 15 |
| Other Customer Revenue | — | — | 10 | 10 |
| Total Customer Revenue | 541 | 511 | 10 | 1,062 |
| Other revenue | 4 | 1 | — | 5 |
| Total operating revenue | $ 545 | $ 512 | $ 10 | $ 1,067 |

| | For the Three-Month Period Ended March 31, 2020 | | | |
|---|---|---|---|---|
| | Electric | Natural Gas | Other | Total |
| Customer Revenue: | | | | |
| Retail: | | | | |
| Residential | $ 148 | $ 128 | $ — | $ 276 |
| Commercial | 70 | 43 | — | 113 |
| Industrial | 163 | 4 | — | 167 |
| Natural gas transportation services | — | 11 | — | 11 |
| Other retail[1] | 29 | — | — | 29 |
| Total retail | 410 | 186 | — | 596 |
| Wholesale | 42 | 22 | — | 64 |
| Multi-value transmission projects | 16 | — | — | 16 |
| Other Customer Revenue | — | — | 1 | 1 |
| Total Customer Revenue | 468 | 208 | 1 | 677 |
| Other revenue | 3 | 1 | — | 4 |
| Total operating revenue | $ 471 | $ 209 | $ 1 | $ 681 |

(1) Other retail includes provisions for rate refunds, for which any actual refunds will be reflected in the applicable customer classes upon resolution of the related regulatory proceeding.

### (10) Segment Information

MidAmerican Energy has identified two reportable 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.

The following tables provide information on a reportable segment basis (in millions):

| | Three-Month Periods Ended March 31, | |
|---|---|---|
| | 2021 | 2020 |
| **Operating revenue:** | | |
| Regulated electric | $ 545 | $ 471 |
| Regulated natural gas | 512 | 209 |
| Other | 10 | 1 |
| Total operating revenue | $ 1,067 | $ 681 |
| | | |
| **Operating income:** | | |
| Regulated electric | $ 9 | $ 59 |
| Regulated natural gas | 39 | 39 |
| Total operating income | 48 | 98 |
| Interest expense | (74) | (76) |
| Allowance for borrowed funds | 2 | 3 |
| Allowance for equity funds | 6 | 8 |
| Other, net | 11 | (5) |
| (Loss) income before income tax benefit | $ (7) | $ 28 |

| | As of | |
|---|---|---|
| | March 31, 2021 | December 31, 2020 |
| **Assets:** | | |
| Regulated electric | $ 20,272 | $ 19,892 |
| Regulated natural gas | 1,725 | 1,544 |
| Other | 3 | 1 |
| Total assets | $ 22,000 | $ 21,437 |

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

To the Board of Managers and Member of
MidAmerican Funding, LLC

**Results of Review of Interim Financial Information**

We have reviewed the accompanying consolidated balance sheet of MidAmerican Funding, LLC and subsidiaries ("MidAmerican Funding") as of March 31, 2021, the related consolidated statements of operations, changes in member's equity, and cash flows for the three-month periods ended March 31, 2021 and 2020, and the related notes (collectively referred to as the "interim financial information"). Based on our reviews, we are not aware of any material modifications that should be made to the accompanying interim financial information for it to be in conformity with accounting principles generally accepted in the United States of America.

We have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB) and in accordance with auditing standards generally accepted in the United States of America, the consolidated balance sheet of MidAmerican Funding as of December 31, 2020, and the related consolidated statements of operations, changes in member's equity, and cash flows for the year then ended (not presented herein); and in our report dated February 26, 2021, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying consolidated balance sheet as of December 31, 2020, is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

**Basis for Review Results**

This interim financial information is the responsibility of MidAmerican Funding's management. We are a public accounting firm registered with the 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 reviews in accordance with standards of the PCAOB and with auditing standards generally accepted in the United States of America applicable to reviews of interim financial information. A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the PCAOB and with auditing standards generally accepted in the United States of America, the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
April 30, 2021

**MIDAMERICAN FUNDING, LLC AND SUBSIDIARIES**
**CONSOLIDATED BALANCE SHEETS (Unaudited)**
(Amounts in millions)

| | As of | |
|---|---|---|
| | March 31, 2021 | December 31, 2020 |
| **ASSETS** | | |
| **Current assets:** | | |
| Cash and cash equivalents | $ 38 | $ 39 |
| Trade receivables, net | 521 | 234 |
| Income tax receivable | 295 | — |
| Inventories | 231 | 278 |
| Other current assets | 102 | 74 |
| Total current assets | 1,187 | 625 |
| | | |
| Property, plant and equipment, net | 19,223 | 19,279 |
| Goodwill | 1,270 | 1,270 |
| Regulatory assets | 439 | 392 |
| Investments and restricted investments | 940 | 913 |
| Other assets | 215 | 232 |
| | | |
| **Total assets** | $ 23,274 | $ 22,711 |

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

**MIDAMERICAN FUNDING, LLC AND SUBSIDIARIES**
**CONSOLIDATED BALANCE SHEETS (Unaudited) (continued)**
(Amounts in millions)

| | As of | |
|---|---|---|
| | March 31, 2021 | December 31, 2020 |
| **LIABILITIES AND MEMBER'S EQUITY** | | |
| **Current liabilities:** | | |
| Accounts payable | $ 292 | $ 408 |
| Accrued interest | 87 | 83 |
| Accrued property, income and other taxes | 124 | 161 |
| Note payable to affiliate | 184 | 177 |
| Short-term debt | 387 | — |
| Other current liabilities | 187 | 183 |
| Total current liabilities | 1,261 | 1,012 |
| | | |
| Long-term debt | 7,464 | 7,450 |
| Regulatory liabilities | 1,257 | 1,111 |
| Deferred income taxes | 3,104 | 3,052 |
| Asset retirement obligations | 711 | 709 |
| Other long-term liabilities | 414 | 458 |
| Total liabilities | 14,211 | 13,792 |
| | | |
| Commitments and contingencies (Note 8) | | |
| | | |
| **Member's equity:** | | |
| Paid-in capital | 1,679 | 1,679 |
| Retained earnings | 7,384 | 7,240 |
| Total member's equity | 9,063 | 8,919 |
| | | |
| **Total liabilities and member's equity** | $ 23,274 | $ 22,711 |

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

**MIDAMERICAN FUNDING, LLC AND SUBSIDIARIES**
**CONSOLIDATED STATEMENTS OF OPERATIONS (Unaudited)**
(Amounts in millions)

| | Three-Month Periods Ended March 31, | |
|---|---|---|
| | **2021** | **2020** |
| **Operating revenue:** | | |
| Regulated electric | $ 545 | $ 471 |
| Regulated natural gas and other | 522 | 215 |
| Total operating revenue | 1,067 | 686 |
| | | |
| **Operating expenses:** | | |
| Cost of fuel and energy | 151 | 80 |
| Cost of natural gas purchased for resale and other | 432 | 129 |
| Operations and maintenance | 193 | 165 |
| Depreciation and amortization | 207 | 176 |
| Property and other taxes | 36 | 34 |
| Total operating expenses | 1,019 | 584 |
| | | |
| **Operating income** | 48 | 102 |
| | | |
| **Other income (expense):** | | |
| Interest expense | (78) | (81) |
| Allowance for borrowed funds | 2 | 3 |
| Allowance for equity funds | 6 | 8 |
| Other, net | 10 | (6) |
| Total other income (expense) | (60) | (76) |
| | | |
| **(Loss) income before income tax benefit** | (12) | 26 |
| Income tax benefit | (156) | (124) |
| | | |
| **Net income** | $ 144 | $ 150 |

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 (Unaudited)**
(Amounts in millions)

| | Paid-in Capital | Retained Earnings | Total Member's Equity |
|---|---|---|---|
| **Balance, December 31, 2019** | $ 1,679 | $ 6,422 | $ 8,101 |
| Net income | — | 150 | 150 |
| **Balance, March 31, 2020** | $ 1,679 | $ 6,572 | $ 8,251 |
| | | | |
| **Balance, December 31, 2020** | $ 1,679 | $ 7,240 | $ 8,919 |
| Net income | — | 144 | 144 |
| **Balance, March 31, 2021** | $ 1,679 | $ 7,384 | $ 9,063 |

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

**MIDAMERICAN FUNDING, LLC AND SUBSIDIARIES**
**CONSOLIDATED STATEMENTS OF CASH FLOWS (Unaudited)**
(Amounts in millions)

| | Three-Month Periods Ended March 31, | |
|---|---|---|
| | **2021** | **2020** |
| **Cash flows from operating activities:** | | |
| Net income | $ 144 | $ 150 |
| Adjustments to reconcile net income to net cash flows from operating activities: | | |
| Depreciation and amortization | 207 | 176 |
| Amortization of utility plant to other operating expenses | 8 | 9 |
| Allowance for equity funds | (6) | (8) |
| Deferred income taxes and amortization of investment tax credits | 153 | 93 |
| Settlements of asset retirement obligations | (4) | (2) |
| Other, net | (3) | 15 |
| Changes in other operating assets and liabilities: | | |
| Trade receivables and other assets | (298) | 16 |
| Inventories | 46 | (6) |
| Derivative collateral, net | (14) | 1 |
| Pension and other postretirement benefit plans | 1 | (6) |
| Accrued property, income and other taxes, net | (332) | (290) |
| Accounts payable and other liabilities | 6 | 66 |
| Net cash flows from operating activities | (92) | 214 |
| | | |
| **Cash flows from investing activities:** | | |
| Capital expenditures | (298) | (472) |
| Purchases of marketable securities | (52) | (127) |
| Proceeds from sales of marketable securities | 47 | 124 |
| Other, net | — | 6 |
| Net cash flows from investing activities | (303) | (469) |
| | | |
| **Cash flows from financing activities:** | | |
| Net change in note payable to affiliate | 7 | 3 |
| Net proceeds from short-term debt | 387 | 50 |
| Other, net | — | (1) |
| Net cash flows from financing activities | 394 | 52 |
| | | |
| **Net change in cash and cash equivalents and restricted cash and cash equivalents** | (1) | (203) |
| **Cash and cash equivalents and restricted cash and cash equivalents at beginning of period** | 46 | 331 |
| **Cash and cash equivalents and restricted cash and cash equivalents at end of period** | $ 45 | $ 128 |

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

**MIDAMERICAN FUNDING, LLC AND SUBSIDIARIES**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**
**(Unaudited)**

## (1) General

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.

The unaudited Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") for interim financial information and the United States Securities and Exchange Commission's rules and regulations for Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all of the disclosures required by GAAP for annual financial statements. Management believes the unaudited Consolidated Financial Statements contain all adjustments (consisting only of normal recurring adjustments) considered necessary for the fair presentation of the unaudited Consolidated Financial Statements as of March 31, 2021, and for the three-month periods ended March 31, 2021 and 2020. The Consolidated Statements of Comprehensive Income have been omitted as net income materially equals comprehensive income for the three-month period ended March 31, 2021 and 2020. The results of operations for the three-month periods ended March 31, 2021, are not necessarily indicative of the results to be expected for the full year.

The preparation of the unaudited Consolidated Financial Statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the unaudited Consolidated Financial Statements and the reported amounts of revenue and expenses during the period. Actual results may differ from the estimates used in preparing the unaudited Consolidated Financial Statements. Note 2 of Notes to Consolidated Financial Statements included in MidAmerican Funding's Annual Report on Form 10-K for the year ended December 31, 2020, describes the most significant accounting policies used in the preparation of the unaudited Consolidated Financial Statements. There have been no significant changes in MidAmerican Funding's assumptions regarding significant accounting estimates and policies during the three-month period ended March 31, 2021.

## (2) 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 March 31, 2021 and December 31, 2020, consist substantially of funds restricted for wildlife preservation and, as of December 31, 2020, the purpose of constructing solid waste facilities under tax-exempt bond obligation agreements. A reconciliation of cash and cash equivalents and restricted cash and cash equivalents as of March 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 | |
|---|---|---|
| | **March 31, 2021** | **December 31, 2020** |
| Cash and cash equivalents | $ 38 | $ 39 |
| Restricted cash and cash equivalents in other current assets | 7 | 7 |
| Total cash and cash equivalents and restricted cash and cash equivalents | $ 45 | $ 46 |

**(3) Property, Plant and Equipment, Net**

Refer to Note 3 of MidAmerican Energy's Notes to Financial Statements.

**(4) Regulatory Matters**

Refer to Note 4 of MidAmerican Energy's Notes to Financial Statements.

**(5) Income Taxes**

The effective income tax rate for the three-month period ended March 31, 2021, is 1,300% and results from a $156 million income tax benefit associated with a $12 million pre-tax loss. The $156 million income tax benefit is primarily comprised of a $3 million benefit (21%) from the application of the statutory income tax rate to the pre-tax loss and a $168 million benefit (1,400%) from income tax credits, partially offset by a $13 million expense (108%) from the effects of ratemaking.

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:

| | Three-Month Periods Ended March 31, | |
|---|---|---|
| | **2021** | **2020** |
| Federal statutory income tax rate | 21 % | 21 % |
| Income tax credits | 1,400 | (463) |
| State income tax, net of federal income tax impacts | (8) | (31) |
| Effects of ratemaking | (108) | (3) |
| Other, net | (5) | (1) |
| Effective income tax rate | 1,300 % | (477)% |

Income tax credits relate primarily to production tax credits ("PTCs") from 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. MidAmerican Funding recognizes its renewable electricity PTCs throughout the year based on when the credits are earned and excludes them from the annual effective tax rate that is the basis for the interim recognition of other income tax expense. 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 three-month periods ended March 31, 2021 and 2020 totaled $151 million and $120 million, respectively.

Berkshire Hathaway includes BHE and subsidiaries in its United States federal and Iowa state income tax returns. Consistent with established regulatory practice, MidAmerican Funding's and MidAmerican Energy's provisions for income tax have been computed on a stand-alone basis, and substantially all of their currently payable or receivable income tax is remitted to or received from BHE. The timing of MidAmerican Funding's income tax cash flows from period to period can be significantly affected by the estimated federal income tax payment methods and assumptions for each payment date. MidAmerican Funding made no cash payments for income tax to BHE for the three-month period ended March 31, 2021, and made net cash payments for income tax to BHE totaling $47 million for the three-month period ended March 31, 2020.

**(6) Employee Benefit Plans**

Refer to Note 6 of MidAmerican Energy's Notes to Financial Statements.

## (7) Fair Value Measurements

Refer to Note 7 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 (in millions):

| | As of March 31, 2021 | | As of December 31, 2020 | |
|---|---|---|---|---|
| | Carrying Value | Fair Value | Carrying Value | Fair Value |
| Long-term debt | $ 7,464 | $ 8,622 | $ 7,450 | $ 9,466 |

## (8) Commitments and Contingencies

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.

Refer to Note 8 of MidAmerican Energy's Notes to Financial Statements.

## (9) Revenue from Contracts with Customers

Refer to Note 9 of MidAmerican Energy's Notes to Financial Statements. Additionally, MidAmerican Funding had other Accounting Standards Codification Topic 606 revenue of $— million and $5 million for the three-month periods ended March 31, 2021 and 2020, respectively.

## (10) Segment Information

MidAmerican Funding has identified two reportable 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 financial results and assets of nonregulated operations, MHC and MidAmerican Funding.

The following tables provide information on a reportable segment basis (in millions):

| | Three-Month Periods Ended March 31, 2021 | Three-Month Periods Ended March 31, 2020 |
|---|---|---|
| **Operating revenue:** | | |
| Regulated electric | $ 545 | $ 471 |
| Regulated natural gas | 512 | 209 |
| Other | 10 | 6 |
| Total operating revenue | $ 1,067 | $ 686 |
| | | |
| **Operating income:** | | |
| Regulated electric | $ 9 | $ 59 |
| Regulated natural gas | 39 | 39 |
| Other | — | 4 |
| Total operating income | 48 | 102 |
| Interest expense | (78) | (81) |
| Allowance for borrowed funds | 2 | 3 |
| Allowance for equity funds | 6 | 8 |
| Other, net | 10 | (6) |
| (Loss) income before income tax benefit | $ (12) | $ 26 |

| | As of March 31, 2021 | As of December 31, 2020 |
|---|---|---|
| **Assets[(1)]:** | | |
| Regulated electric | $ 21,463 | $ 21,083 |
| Regulated natural gas | 1,804 | 1,623 |
| Other | 7 | 5 |
| Total assets | $ 23,274 | $ 22,711 |

(1) Assets by reportable segment reflect the assignment of goodwill to applicable reporting units.

## Item 2. 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 unaudited Consolidated Financial Statements and Notes to Consolidated Financial Statements and MidAmerican Energy's historical unaudited Financial Statements and Notes to Financial Statements in Part I, Item 1 of this Form 10-Q. MidAmerican Funding's and MidAmerican Energy's actual results in the future could differ significantly from the historical results.

### Results of Operations for the First Quarter of 2021 and 2020

<u>Overview</u>

MidAmerican Energy -

MidAmerican Energy's net income for the first quarter of 2021 was $147 million, a decrease of $4 million, or 3%, compared to 2020 primarily due to higher depreciation and amortization expense of $31 million from additional assets placed in-service and the expiration of a regulatory mechanism deferring certain depreciation expense, and higher operations and maintenance expenses of $28 million, partially offset by a greater income tax benefit of $31 million from higher PTCs recognized, higher investment earnings of $19 million and higher company-retained margins of $9 million on natural gas wholesale sales. PTCs recognized increased due to higher wind-powered generation driven primarily by new wind projects placed in-service.

MidAmerican Funding -

MidAmerican Funding's net income for the first quarter of 2021 was $144 million, a decrease of $6 million, or 4%, compared to 2020. The decrease was primarily due to the changes in MidAmerican Energy's earnings discussed above.

<u>Non-GAAP Financial Measure</u>

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 regulated 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 expense 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 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 comparable financial measure prepared in accordance with GAAP. The following table provides a reconciliation of utility margin to MidAmerican Energy's operating income (in millions):

| | First Quarter | | | |
|---|---|---|---|---|
| | 2021 | 2020 | Change | |
| **Electric utility margin:** | | | | |
| Operating revenue | $ 545 | $ 471 | $ 74 | 16 % |
| Cost of fuel and energy | 151 | 80 | 71 | 89 |
| **Electric utility margin** | 394 | 391 | 3 | 1 % |
| | | | | |
| **Natural gas utility margin:** | | | | |
| Operating revenue | 512 | 209 | 303 | 145 % |
| Natural gas purchased for resale | 432 | 128 | 304 | 238 |
| **Natural gas utility margin** | 80 | 81 | (1) | (1)% |
| | | | | |
| **Utility margin** | 474 | 472 | 2 | — % |
| | | | | |
| Other operating revenue | 10 | 1 | 9 | * |
| Operations and maintenance | 193 | 165 | 28 | 17 |
| Depreciation and amortization | 207 | 176 | 31 | 18 |
| Property and other taxes | 36 | 34 | 2 | 6 |
| **Operating income** | $ 48 | $ 98 | $ (50) | (51)% |

Electric Utility Margin

A comparison of key operating results related to electric utility margin is as follows for the quarters ended March 31:

| | First Quarter | | | |
|---|---|---|---|---|
| | 2021 | 2020 | Change | |
| **Utility margin (in millions):** | | | | |
| Operating revenue | $ 545 | $ 471 | $ 74 | 16 % |
| Cost of fuel and energy | 151 | 80 | 71 | 89 |
| Utility margin | $ 394 | $ 391 | $ 3 | 1 % |
| | | | | |
| **Sales (GWhs):** | | | | |
| Residential | 1,738 | 1,668 | 70 | 4 % |
| Commercial | 938 | 969 | (31) | (3) |
| Industrial | 3,819 | 3,524 | 295 | 8 |
| Other | 370 | 385 | (15) | (4) |
| Total retail | 6,865 | 6,546 | 319 | 5 |
| Wholesale | 4,051 | 2,434 | 1,617 | 66 |
| Total sales | 10,916 | 8,980 | 1,936 | 22 % |
| | | | | |
| **Average number of retail customers (in thousands)** | 801 | 792 | 9 | 1 % |
| | | | | |
| **Average revenue per MWh:** | | | | |
| Retail | $ 65.82 | $ 62.75 | $ 3.07 | 5 % |
| Wholesale | $ 16.64 | $ 15.71 | $ 0.93 | 6 % |
| | | | | |
| **Heating degree days** | 3,211 | 2,952 | 259 | 9 % |
| | | | | |
| **Sources of energy (GWhs)[(1)]:** | | | | |
| Wind and other[(2)] | 6,122 | 4,846 | 1,276 | 26 % |
| Coal | 2,902 | 1,573 | 1,329 | 84 |
| Nuclear | 895 | 993 | (98) | (10) |
| Natural gas | 143 | 116 | 27 | 23 |
| Total energy generated | 10,062 | 7,528 | 2,534 | 34 |
| Energy purchased | 1,018 | 1,643 | (625) | (38) |
| Total | 11,080 | 9,171 | 1,909 | 21 % |
| | | | | |
| **Average cost of energy per MWh:** | | | | |
| Energy generated[(3)] | $ 6.15 | $ 5.00 | $ 1.15 | 23 % |
| Energy purchased | $ 87.45 | $ 25.59 | $ 61.86 | * |

* 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 generating facilities 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 quarters ended March 31:

| | First Quarter | | | |
|---|---|---|---|---|
| | 2021 | 2020 | Change | |
| **Utility margin (in millions):** | | | | |
| Operating revenue | $ 512 | $ 209 | $ 303 | * |
| Natural gas purchased for resale | 432 | 128 | 304 | * |
| Utility margin | $ 80 | $ 81 | $ (1) | (1) % |
| **Throughput (000's Dths):** | | | | |
| Residential | 25,282 | 23,910 | 1,372 | 6 % |
| Commercial | 11,733 | 10,951 | 782 | 7 |
| Industrial | 1,437 | 1,512 | (75) | (5) |
| Other | 37 | 35 | 2 | 6 |
| Total retail sales | 38,489 | 36,408 | 2,081 | 6 |
| Wholesale sales | 10,773 | 12,910 | (2,137) | (17) |
| Total sales | 49,262 | 49,318 | (56) | — |
| Natural gas transportation service | 29,640 | 34,954 | (5,314) | (15) |
| Total throughput | 78,902 | 84,272 | (5,370) | (6) % |
| **Average number of retail customers (in thousands)** | 777 | 770 | 7 | 1 % |
| **Average revenue per retail Dth sold** | $ 11.70 | $ 4.85 | $ 6.85 | * |
| **Heating degree days** | 3,301 | 3,067 | 234 | 8 % |
| **Average cost of natural gas per retail Dth sold** | $ 9.87 | $ 2.91 | $ 6.96 | * |
| **Combined retail and wholesale average cost of natural gas per Dth sold** | $ 8.76 | $ 2.60 | $ 6.16 | * |

* Not meaningful.

Quarter Ended March 31, 2021 Compared to Quarter Ended March 31, 2020

MidAmerican Energy -

*Electric utility margin* increased $3 million for the first quarter of 2021 compared to 2020, due to:

- a $15 million increase in retail utility margin due to an increase of $6 million, net of energy costs, from higher recoveries through bill riders (offset in operations and maintenance expense and income tax benefit); an increase of $6 million from the favorable impact of weather; and an increase of $4 million due to price impacts from changes in sales mix and other rate and usage variances, including increased usage for certain industrial customers; partially offset by
- a $12 million decrease in wholesale utility margin due to lower margins per unit, reflecting higher energy costs, partially offset by higher sales volumes of 66.4%.

*Natural gas utility margin* decreased $1 million for the first quarter of 2021 compared to 2020 primarily due to:

- a $7 million decrease from higher rider refunds related to the ratemaking treatment of 2017 Tax Reform (offset in income tax benefit); partially offset by
- $3 million from higher natural gas energy efficiency program revenue (offset in operations and maintenance expense); and
- $2 million from the favorable impact of weather.

*Operations and maintenance* increased $28 million for the first quarter of 2021 compared to 2020 primarily due to higher generation operations and maintenance expenses of $6 million due to additional wind turbines and easements, higher electric and natural gas distribution costs of $6 million, higher energy efficiency program expense of $5 million (offset in operating revenue) and higher employee-related expenses of $5 million.

*Depreciation and amortization* for the first quarter of 2021 increased $31 million compared to 2020 primarily due to wind-powered generating facilities and other plant placed in-service and $13 million from the expiration of a regulatory mechanism deferring certain depreciation expense.

*Interest expense* decreased $2 million for the first quarter of 2021 compared to 2020 due to lower average interest rates on variable rate long-term debt.

*Allowance for borrowed and equity funds* decreased $3 million for the first quarter of 2021 compared to 2020 primarily due to lower construction work-in-progress balances related to wind-powered generation.

*Other, net* increased $16 million for the first quarter of 2021 compared to 2020 primarily due to higher cash surrender values of corporate-owned life insurance policies.

*Income tax benefit* increased $31 million for the first quarter of 2021 compared to 2020, and the effective tax rate was 2,200% for 2021 and (439)% for 2020. The change in the effective tax rates for 2021 compared to 2020 was due to the higher PTCs and a lower pretax income, partially offset by the effects of ratemaking and state income tax impacts.

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, including those facilities where a significant portion of the equipment was replaced, commonly referred to as repowered facilities, are eligible for the credits for 10 years from the date the qualifying generating facilities are placed in-service. PTCs for the first quarter of 2021 and 2020 totaled $151 million and $120 million, respectively.

MidAmerican Funding -

*Income tax benefit* increased $32 million for the first quarter of 2021 compared to 2020, and the effective tax rate was 1,300% for 2021 and (477)% for 2020. The changes in the effective tax rates were principally due to the factors discussed for MidAmerican Energy.

**Liquidity and Capital Resources**

As of March 31, 2021, the total net liquidity for MidAmerican Energy and MidAmerican Funding was as follows (in millions):

| | | |
|---|---|---|
| **MidAmerican Energy:** | | |
| Cash and cash equivalents | $ | 37 |
| | | |
| Credit facilities, maturing 2021 and 2022 | | 1,505 |
| Less: | | |
| Short-term debt outstanding | | (387) |
| Tax-exempt bond support | | (370) |
| Net credit facilities | | 748 |
| | | |
| MidAmerican Energy total net liquidity | $ | 785 |
| | | |
| **MidAmerican Funding:** | | |
| MidAmerican Energy total net liquidity | $ | 785 |
| Cash and cash equivalents | | 1 |
| MHC, Inc. credit facility, maturing 2021 | | 4 |
| MidAmerican Funding total net liquidity | $ | 790 |

Operating Activities

MidAmerican Energy's net cash flows from operating activities for the three-month periods ended March 31, 2021 and 2020, were $(85) million and $219 million, respectively. MidAmerican Funding's net cash flows from operating activities for the three-month periods ended March 31, 2021 and 2020, were $(92) million and $214 million, respectively. Cash flows from operating activities reflect lower cash margins for MidAmerican Energy's regulated electric and natural gas businesses, including delayed recovery of higher natural gas costs in February 2021, discussed below, and higher payments to vendors.

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 MidAmerican Energy's customers, the IUB ordered the recovery of these higher costs to be applied to sales over the period April 2021 through April 2022. While sufficient liquidity is available to MidAmerican Energy, the increased costs and longer recovery period resulted in higher working capital requirements during three-month period ended March 31, 2021.

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 and assumptions for each payment date.

Investing Activities

MidAmerican Energy's net cash flows from investing activities for the three-month periods ended March 31, 2021 and 2020, were $(303) million and $(470) million, respectively. MidAmerican Funding's net cash flows from investing activities for the three-month periods ended March 31, 2021 and 2020, were $(303) million and $(469) million, respectively. Net cash flows from investing activities consist almost entirely of capital expenditures, which decreased primarily due to lower wind-powered generating facility construction expenditures. Purchases and proceeds related to marketable securities substantially consist of activity within the Quad Cities Generating Station nuclear decommissioning trust and other trust investments.

Financing Activities

MidAmerican Energy's net cash flows from financing activities for the three-month periods ended March 31, 2021 and 2020 were $387 million and $49 million, respectively. MidAmerican Funding's net cash flows from financing activities for the three-month periods ended March 31, 2021 and 2020, were $394 million and $52 million, respectively. Through its commercial paper program, MidAmerican Energy received $387 million in 2021 and $50 million in 2020. MidAmerican Funding received $7 million and $3 million in 2021 and 2020, respectively, through its note payable with BHE.

*Debt Authorizations and Related Matters*

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 $900 million unsecured credit facility expiring in June 2022. 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. MidAmerican Energy has a $600 million unsecured credit facility, which, following MidAmerican Energy's exercise of an option to extend the facility, expires in August 2021, and has a variable interest rate based on the Eurodollar rate or a base rate, at MidAmerican Energy's option, plus a spread. Additionally, MidAmerican Energy has a $5 million unsecured credit facility for general corporate purposes.

MidAmerican Energy currently has an effective automatic registration statement with the SEC to issue an indeterminate amount of long-term debt securities through June 26, 2021. Additionally, MidAmerican Energy has authorization from the FERC to issue, through June 30, 2021, long-term debt securities up to an aggregate of $850 million at interest rates not to exceed the applicable United States Treasury rate plus a spread of 175 basis points 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 $850 million through August 20, 2022.

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 regulatory approvals, 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, are as follows (in millions):

| | Three-Month Periods Ended March 31, 2020 | Three-Month Periods Ended March 31, 2021 | Annual Forecast 2021 |
|---|---|---|---|
| Wind generation | $ 166 | $ 32 | $ 865 |
| Electric distribution | 51 | 46 | 298 |
| Electric transmission | 38 | 23 | 197 |
| Solar generation | — | 3 | 245 |
| Other | 217 | 194 | 595 |
| Total | $ 472 | $ 298 | $ 2,200 |

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 $154 million for 2020. MidAmerican Energy's forecast expenditures in 2021 for the construction of additional wind-powered generating facilities total $391 million and include 202 MWs of wind-powered generating facilities expected to be placed in-service in 2021.
  - Repowering of wind-powered generating facilities totaled $24 million for 2021 and $6 million for 2020. Planned spending for repowering generating facilities totals $379 million for the remainder of 2021. MidAmerican Energy expects its repowered facilities to meet Internal Revenue Service 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 1,078 MWs of current repowering projects not in-service as of March 31, 2021, 80 MWs are currently expected to qualify for 100% of the PTCs available for 10 years following each facility's return to service, 591 MWs are expected to qualify for 80% of such credits and 407 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 reflects MidAmerican Energy's current plan for the construction of 117 MWs of small- and utility-scale solar generation during 2021, of which 37 MWs are expected to be placed in-service in 2021.
- Remaining expenditures primarily relate to routine expenditures for other generation, natural gas distribution, technology, facilities and other operational needs to serve existing and expected demand.

*Contractual Obligations*

As of March 31, 2021, there have been no material changes outside the normal course of business in MidAmerican Energy's and MidAmerican Funding's contractual obligations from the information provided in Item 7 of their Annual Report on Form 10-K for the year ended December 31, 2020.

**Quad Cities Generating Station Operating Status**

Exelon Generation Company, LLC ("Exelon Generation"), 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 zero emission credits ("ZECs") and recover the costs from certain ratepayers in Illinois, subject to certain limitations. The proceeds from the ZECs will provide Exelon Generation 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 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 expands the breadth and scope of the PJM's MOPR, which is effective as of the PJM's next capacity auction. While the FERC included some limited exemptions in its order, 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. On October 15, 2020, the FERC issued an order denying requests for rehearing of its April 16, 2020 order and accepting the PJM's two compliance filings, subject to a further compliance filing to revise minor aspects of the proposed MOPR methodology. As part of that order, the FERC also accepted the PJM's proposal to condense the schedule of activities leading up to the next capacity auction but did not specify when that schedule would commence given that a key element of the MOPR level computation remains pending before the FERC in another proceeding. In November 2020, the PJM announced that the next capacity auction will be conducted in May 2021.

On May 21, 2020, the FERC issued an order involving reforms to the PJM's day-ahead and real-time reserves markets that need to be reflected in the calculation of MOPR levels. In approving reforms to the PJM's reserves markets, the FERC also directed the PJM to develop a new methodology for estimating revenues that resources will receive for sales of energy and related services, which will then be used in calculating a number of parameters and assumptions used in the capacity market, including MOPR levels. The PJM submitted its new revenue projection methodology on August 5, 2020. On review of this compliance filing, the FERC is expected to address how these additional reforms will impact MOPR levels, the timeline for implementing the new revenue projection methodology, and the timing for commencing the capacity auction schedule.

Exelon Generation is currently working with the PJM and other stakeholders to pursue the FRR option as an alternative to the next PJM capacity auction. If Illinois implements the FRR option, Quad Cities Station could be removed from the PJM's capacity auction and instead supply capacity and be compensated under the FRR program. If Illinois cannot implement an FRR program in its PJM zones, then the MOPR will apply to Quad Cities Station, resulting in higher offers for its units that may not clear the capacity market. Implementing the FRR program in Illinois will require both legislative and regulatory changes. MidAmerican Energy cannot predict whether or when such legislative and regulatory changes can be implemented or their potential impact on the continued operation of Quad Cities Station.

**Regulatory Matters**

MidAmerican Energy is subject to comprehensive regulation. Refer to "Regulatory Matters" in Berkshire Hathaway Energy's Part I, Item 2 of this Form 10-Q for discussion regarding MidAmerican Energy's current regulatory matters.

**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 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 the EPA and various 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 consolidated financial results. MidAmerican Energy believes it is in material compliance with all applicable laws and regulations.

Refer to "Environmental Laws and Regulations" in Berkshire Hathaway Energy's Part I, Item 2 of this Form 10-Q for additional information regarding environmental laws and regulations.

**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. Estimates are used for, but not limited to, the accounting for the effects of certain types of regulation, derivatives, impairment of goodwill and long-lived assets, pension and other postretirement benefits, income taxes and revenue recognition - unbilled revenue. For additional discussion of MidAmerican Energy's and MidAmerican Funding's critical accounting estimates, see Item 7 of their Annual Report on Form 10-K for the year ended December 31, 2020. There have been no significant changes in MidAmerican Energy's and MidAmerican Funding's assumptions regarding critical accounting estimates since December 31, 2020.

## Nevada Power Company and its subsidiaries
## Consolidated Financial Section

## PART I

**Item 1. Financial Statements**

## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Nevada Power Company

**Results of Review of Interim Financial Information**

We have reviewed the accompanying consolidated balance sheet of Nevada Power Company and subsidiaries ("Nevada Power") as of March 31, 2021, the related consolidated statements of operations, changes in shareholder's equity and cash flows for the three-month periods ended March 31, 2021 and 2020, and the related notes (collectively referred to as the "interim financial information"). Based on our reviews, we are not aware of any material modifications that should be made to the accompanying interim financial information for it to be in conformity with accounting principles generally accepted in the United States of America.

We have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheet of Nevada Power as of December 31, 2020, and the related consolidated statements of operations, changes in shareholder's equity, and cash flows for the year then ended (not presented herein); and in our report dated February 26, 2021, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying consolidated balance sheet as of December 31, 2020, is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

**Basis for Review Results**

This interim financial information is the responsibility of Nevada Power's management. We are a public accounting firm registered with the 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 reviews in accordance with standards of the PCAOB. A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the PCAOB, the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

/s/ Deloitte & Touche LLP

Las Vegas, Nevada
April 30, 2021

**NEVADA POWER COMPANY AND SUBSIDIARIES**
**CONSOLIDATED BALANCE SHEETS (Unaudited)**
(Amounts in millions, except share data)

| | As of | |
|---|---|---|
| | **March 31, 2021** | **December 31, 2020** |
| **ASSETS** | | |
| **Current assets:** | | |
| Cash and cash equivalents | $ 92 | $ 25 |
| Trade receivables, net | 180 | 234 |
| Inventories | 65 | 69 |
| Derivative contracts | 48 | 26 |
| Regulatory assets | 22 | 48 |
| Prepayments | 45 | 38 |
| Other current assets | 37 | 26 |
| Total current assets | 489 | 466 |
| | | |
| Property, plant and equipment, net | 6,751 | 6,701 |
| Finance lease right of use assets, net | 348 | 351 |
| Regulatory assets | 741 | 746 |
| Other assets | 71 | 72 |
| | | |
| **Total assets** | $ 8,400 | $ 8,336 |
| | | |
| **LIABILITIES AND SHAREHOLDER'S EQUITY** | | |
| **Current liabilities:** | | |
| Accounts payable | $ 189 | $ 181 |
| Accrued interest | 38 | 32 |
| Accrued property, income and other taxes | 38 | 25 |
| Current portion of finance lease obligations | 30 | 27 |
| Regulatory liabilities | 63 | 50 |
| Customer deposits | 42 | 47 |
| Asset retirement obligation | 18 | 25 |
| Other current liabilities | 38 | 22 |
| Total current liabilities | 456 | 409 |
| | | |
| Long-term debt | 2,497 | 2,496 |
| Finance lease obligations | 328 | 334 |
| Regulatory liabilities | 1,171 | 1,163 |
| Deferred income taxes | 740 | 738 |
| Other long-term liabilities | 267 | 257 |
| Total liabilities | 5,459 | 5,397 |
| | | |
| Commitments and contingencies (Note 6) | | |
| | | |
| **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 | 636 | 634 |
| Accumulated other comprehensive loss, net | (3) | (3) |
| Total shareholder's equity | 2,941 | 2,939 |
| | | |
| **Total liabilities and shareholder's equity** | $ 8,400 | $ 8,336 |

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

## NEVADA POWER COMPANY AND SUBSIDIARIES
## CONSOLIDATED STATEMENTS OF OPERATIONS (Unaudited)
(Amounts in millions)

| | Three-Month Periods Ended March 31, | |
|---|---|---|
| | 2021 | 2020 |
| **Operating revenue** | $ 370 | $ 389 |
| **Operating expenses:** | | |
| Cost of fuel and energy | 165 | 170 |
| Operations and maintenance | 63 | 82 |
| Depreciation and amortization | 101 | 90 |
| Property and other taxes | 12 | 12 |
| Total operating expenses | 341 | 354 |
| | | |
| **Operating income** | 29 | 35 |
| | | |
| **Other income (expense):** | | |
| Interest expense | (38) | (42) |
| Allowance for borrowed funds | 1 | 1 |
| Allowance for equity funds | 1 | 2 |
| Other, net | 9 | (1) |
| Total other income (expense) | (27) | (40) |
| | | |
| **Income (loss) before income tax benefit** | 2 | (5) |
| Income tax benefit | — | (1) |
| **Net income (loss)** | $ 2 | $ (4) |

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 (Unaudited)**
(Amounts in millions, except shares)

| | Common Stock | | Additional Paid-in | Retained | Accumulated Other Comprehensive | Total Shareholder's |
|---|---|---|---|---|---|---|
| | Shares | Amount | Capital | Earnings | Loss, Net | Equity |
| **Balance, December 31, 2019** | 1,000 | $ — | $ 2,308 | $ 493 | $ (4) | $ 2,797 |
| Net loss | — | — | — | (4) | — | (4) |
| Other equity transactions | — | — | — | 1 | — | 1 |
| **Balance, March 31, 2020** | 1,000 | $ — | $ 2,308 | $ 490 | $ (4) | $ 2,794 |
| | | | | | | |
| **Balance, December 31, 2020** | 1,000 | $ — | $ 2,308 | $ 634 | $ (3) | $ 2,939 |
| Net income | — | — | — | 2 | — | 2 |
| **Balance, March 31, 2021** | 1,000 | $ — | $ 2,308 | $ 636 | $ (3) | $ 2,941 |

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

**NEVADA POWER COMPANY AND SUBSIDIARIES**
**CONSOLIDATED STATEMENTS OF CASH FLOWS (Unaudited)**
(Amounts in millions)

| | Three-Month Periods Ended March 31, | |
|---|---|---|
| | **2021** | **2020** |
| **Cash flows from operating activities:** | | |
| Net income (loss) | $ 2 | $ (4) |
| Adjustments to reconcile net income (loss) to net cash flows from operating activities: | | |
| Depreciation and amortization | 101 | 90 |
| Allowance for equity funds | (1) | (2) |
| Changes in regulatory assets and liabilities | (15) | 3 |
| Deferred income taxes and amortization of investment tax credits | (10) | (4) |
| Deferred energy | 41 | 4 |
| Other, net | (1) | 8 |
| Changes in other operating assets and liabilities: | | |
| Trade receivables and other assets | 41 | 32 |
| Inventories | 4 | (1) |
| Accrued property, income and other taxes | 3 | (6) |
| Accounts payable and other liabilities | 14 | (41) |
| Net cash flows from operating activities | 179 | 79 |
| | | |
| **Cash flows from investing activities:** | | |
| Capital expenditures | (106) | (111) |
| Net cash flows from investing activities | (106) | (111) |
| | | |
| **Cash flows from financing activities:** | | |
| Proceeds from long-term debt | — | 719 |
| Repayments of long-term debt | — | (575) |
| Other, net | (5) | (4) |
| Net cash flows from financing activities | (5) | 140 |
| | | |
| **Net change in cash and cash equivalents and restricted cash and cash equivalents** | 68 | 108 |
| **Cash and cash equivalents and restricted cash and cash equivalents at beginning of period** | 36 | 25 |
| **Cash and cash equivalents and restricted cash and cash equivalents at end of period** | $ 104 | $ 133 |

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

**NEVADA POWER COMPANY AND SUBSIDIARIES**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**
**(Unaudited)**

## (1) General

Nevada Power Company, together with 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 the 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").

The unaudited Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") for interim financial information and the United States Securities and Exchange Commission's rules and regulations for Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all of the disclosures required by GAAP for annual financial statements. Management believes the unaudited Consolidated Financial Statements contain all adjustments (consisting only of normal recurring adjustments) considered necessary for the fair presentation of the unaudited Consolidated Financial Statements as of March 31, 2021 and for the three-month periods ended March 31, 2021 and 2020. The Consolidated Statements of Comprehensive Income have been omitted as net income equals comprehensive income for the three-month periods ended March 31, 2021 and 2020. The results of operations for the three-month period ended March 31, 2021 are not necessarily indicative of the results to be expected for the full year.

The preparation of the unaudited Consolidated Financial Statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the unaudited Consolidated Financial Statements and the reported amounts of revenue and expenses during the period. Actual results may differ from the estimates used in preparing the unaudited Consolidated Financial Statements. Note 2 of Notes to Consolidated Financial Statements included in Nevada Power's Annual Report on Form 10-K for the year ended December 31, 2020 describes the most significant accounting policies used in the preparation of the unaudited Consolidated Financial Statements. There have been no significant changes in Nevada Power's assumptions regarding significant accounting estimates and policies during the three-month period ended March 31, 2021.

## (2) 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 March 31, 2021 and December 31, 2020, consist of funds restricted by the Public Utilities Commission of Nevada ("PUCN") for a certain renewable energy contract. A reconciliation of cash and cash equivalents and restricted cash and cash equivalents as of March 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 | |
|---|---|---|
| | **March 31, 2021** | **December 31, 2020** |
| Cash and cash equivalents | $ 92 | $ 25 |
| Restricted cash and cash equivalents included in other current assets | 12 | 11 |
| Total cash and cash equivalents and restricted cash and cash equivalents | $ 104 | $ 36 |

### (3) Property, Plant and Equipment, Net

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

| | Depreciable Life | As of March 31, 2021 | As of December 31, 2020 |
|---|---|---|---|
| Utility plant: | | | |
| Generation | 30 - 55 years | $ 3,691 | $ 3,690 |
| Transmission | 45 - 70 years | 1,465 | 1,468 |
| Distribution | 20 - 65 years | 3,803 | 3,771 |
| General and intangible plant | 5 - 65 years | 798 | 791 |
| Utility plant | | 9,757 | 9,720 |
| Accumulated depreciation and amortization | | (3,224) | (3,162) |
| Utility plant, net | | 6,533 | 6,558 |
| Other non-regulated, net of accumulated depreciation and amortization | 45 years | 1 | 1 |
| Plant, net | | 6,534 | 6,559 |
| Construction work-in-progress | | 217 | 142 |
| Property, plant and equipment, net | | $ 6,751 | $ 6,701 |

### (4) 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. 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 (in millions):

| | As of March 31, 2021 | As of December 31, 2020 |
|---|---|---|
| **Qualified Pension Plan:** | | |
| Other non-current assets | $ 9 | $ 8 |
| **Non-Qualified Pension Plans:** | | |
| Other current liabilities | (1) | (1) |
| Other long-term liabilities | (9) | (9) |
| **Other Postretirement Plans:** | | |
| Other non-current assets | 4 | 4 |

## (5) 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 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 March 31, 2021** | | | | |
| **Assets:** | | | | |
| Commodity derivatives | $ — | $ — | $ 48 | $ 48 |
| Money market mutual funds[1] | 86 | — | — | 86 |
| Investment funds | 2 | — | — | 2 |
| | $ 88 | $ — | $ 48 | $ 136 |
| **Liabilities - commodity derivatives** | $ — | $ — | $ (21) | $ (21) |
| **As of December 31, 2020** | | | | |
| **Assets:** | | | | |
| Commodity derivatives | $ — | $ — | $ 26 | $ 26 |
| Money market mutual funds[1] | 21 | — | — | 21 |
| Investment funds | 2 | — | — | 2 |
| | $ 23 | $ — | $ 26 | $ 49 |
| **Liabilities - commodity derivatives** | $ — | $ — | $ (11) | $ (11) |

(1) Amounts are included in cash and cash equivalents on the Consolidated Balance Sheets. The fair value of these money market mutual funds approximates cost.

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 March 31, 2021 and December 31, 2020, 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 investment funds are stated at fair value. When available, a readily observable quoted market price or net asset value of an identical security in an active market is used to record the fair value.

The following table reconciles the beginning and ending balances of Nevada Power's commodity derivative assets and liabilities measured at fair value on a recurring basis using significant Level 3 inputs (in millions):

| | Three-Month Periods Ended March 31, | |
|---|---|---|
| | **2021** | **2020** |
| **Beginning balance** | $ 15 | $ (8) |
| Changes in fair value recognized in regulatory assets | 11 | (31) |
| Settlements | 1 | 1 |
| **Ending balance** | $ 27 | $ (38) |

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 carrying value of Nevada Power'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 Nevada Power's long-term debt (in millions):

| | As of March 31, 2021 | | As of December 31, 2020 | |
|---|---|---|---|---|
| | **Carrying Value** | **Fair Value** | **Carrying Value** | **Fair Value** |
| Long-term debt | $ 2,497 | $ 2,991 | $ 2,496 | $ 3,245 |

## (6) Commitments and Contingencies

*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.

*Environmental Laws and Regulations*

Nevada Power is subject to federal, state and local 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 Nevada Power's current and future operations. Nevada Power believes it is in material compliance with all applicable laws and regulations.

## (7) Revenue from Contracts with Customers

The following table summarizes Nevada Power's revenue from contracts with customers ("Customer Revenue") by customer class (in millions):

| | Three-Month Periods Ended March 31, | |
|---|---|---|
| | **2021** | **2020** |
| Customer Revenue: | | |
| Retail: | | |
| Residential | $ 196 | $ 193 |
| Commercial | 84 | 94 |
| Industrial | 63 | 70 |
| Other | 3 | 3 |
| Total fully bundled | 346 | 360 |
| Distribution only service | 5 | 7 |
| Total retail | 351 | 367 |
| Wholesale, transmission and other | 14 | 16 |
| Total Customer Revenue | 365 | 383 |
| Other revenue | 5 | 6 |
| Total revenue | $ 370 | $ 389 |

## Item 2. 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 unaudited Consolidated Financial Statements and Notes to Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q. Nevada Power's actual results in the future could differ significantly from the historical results.

### Results of Operations for the First Quarter of 2021 and 2020

Overview

Net income for the first quarter of 2021 was $2 million, an increase of $6 million, compared to 2020 primarily due to $19 million of lower operations and maintenance expenses, primarily due to lower net regulatory instructed deferrals and amortizations of $11 million, lower plant operations and maintenance costs and a reduction to the accrual for earning sharing, $10 million of higher other, net, mainly due to higher cash surrender value of corporate-owned life insurance policies of $7 million and lower pension expense, and lower interest expense of $4 million. This increase is offset by $14 million of lower utility margin. primarily due to lower retail rates from the 2020 regulatory rate review with new rates effective January 2021, and $11 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.

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 electric 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 are directly recovered from its customers through regulatory recovery mechanisms and as a result, changes in Nevada Power's expenses 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 sales 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 (in millions):

| | First Quarter | | | |
|---|---|---|---|---|
| | 2021 | 2020 | Change | |
| **Utility margin:** | | | | |
| Operating revenue | $ 370 | $ 389 | $ (19) | (5)% |
| Cost of fuel and energy | 165 | 170 | (5) | (3) |
| **Utility margin** | 205 | 219 | (14) | (6) |
| Operations and maintenance | 63 | 82 | (19) | (23) |
| Depreciation and amortization | 101 | 90 | 11 | 12 |
| Property and other taxes | 12 | 12 | — | — |
| **Operating income** | $ 29 | $ 35 | $ (6) | (17)% |

Utility Margin

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

| | First Quarter | | | |
|---|---|---|---|---|
| | 2021 | 2020 | Change | |
| **Utility margin (in millions):** | | | | |
| Operating revenue | $ 370 | $ 389 | $ (19) | (5)% |
| Cost of fuel and energy | 165 | 170 | (5) | (3) |
| Utility margin | $ 205 | $ 219 | $ (14) | (6)% |
| | | | | |
| **Sales (GWhs):** | | | | |
| Residential | 1,587 | 1,544 | 43 | 3 % |
| Commercial | 954 | 1,011 | (57) | (6) |
| Industrial | 1,057 | 1,151 | (94) | (8) |
| Other | 47 | 48 | (1) | (2) |
| Total fully bundled[(1)] | 3,645 | 3,754 | (109) | (3) |
| Distribution only service | 516 | 611 | (95) | (16) |
| Total retail | 4,161 | 4,365 | (204) | (5) |
| Wholesale | 84 | 153 | (69) | (45) |
| Total GWhs sold | 4,245 | 4,518 | (273) | (6)% |
| | | | | |
| **Average number of retail customers (in thousands)** | 978 | 961 | 17 | 2 % |
| | | | | |
| **Average revenue per MWh:** | | | | |
| Retail - fully bundled[(1)] | $ 95.01 | $ 96.01 | $ (1.00) | (1)% |
| Wholesale | $ 49.42 | $ 31.58 | $ 17.84 | 56 % |
| | | | | |
| **Heating degree days** | 994 | 942 | 52 | 6 % |
| **Cooling degree days** | 6 | 2 | 4 | * |
| | | | | |
| **Sources of energy (GWhs)[(2)(3)]:** | | | | |
| Natural gas | 2,534 | 2,622 | (88) | (3)% |
| Renewables | 16 | 16 | — | — |
| Total energy generated | 2,550 | 2,638 | (88) | (3) |
| Energy purchased | 1,355 | 1,240 | 115 | 9 |
| Total | 3,905 | 3,878 | 27 | 1 % |
| | | | | |
| **Average cost of energy per MWh[(4)]:** | | | | |
| Energy generated | $ 14.96 | $ 21.95 | $ (6.99) | (32)% |
| Energy purchased | $ 93.84 | $ 90.56 | $ 3.28 | 4 % |

* Not meaningful

(1) Fully bundled includes sales to customers for combined energy, transmission and distribution services.

(2) The average cost of energy per MWh and sources of energy excludes 683 GWhs and 710 GWhs of gas generated energy that is purchased at cost by related parties for the first quarter of 2021 and 2020, respectively.

(3) GWh amounts are net of energy used by the related generating facilities.

(4) The average cost of energy per MWh includes the cost of fuel, purchased power and deferrals and does not include other costs.

Quarter Ended March 31, 2021 Compared to Quarter Ended March 31, 2020

*Utility margin* decreased $14 million, or 6%, for the first quarter of 2021 compared to 2020 primarily due to:

- $9 million of lower retail rates due to the 2020 regulatory rate review with new rates effective January 2021,
- $2 million due to lower energy efficiency program rates (offset in operations and maintenance expense),
- $1 million due to price impacts from changes in sales mix. Retail customer volumes, including distribution only service customers, decreased 4.7% primarily due to the impacts of COVID-19, which resulted in lower industrial, commercial and distribution only service customer usage and higher residential customer usage, offset by the favorable impacts of weather and
- $1 million of lower other revenue due to a regulatory amortization of impact fee that ended December 2020.

*Operations and maintenance* decreased $19 million, or 23%, for the first quarter of 2021 compared to 2020 primarily due to lower net regulatory instructed deferrals and amortizations of $11 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 plant operations and maintenance costs, a reduction to the accrual for earning sharing and lower energy efficiency program costs (offset in operating revenue).

*Depreciation and amortization* increased $11 million, or 12%, for the first quarter of 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 $4 million, or 10%, for the first quarter of 2021 compared to 2020 primarily due to lower interest expense on long-term debt.

*Other, net* increased $10 million for the first quarter of 2021 compared to 2020 primarily due to higher cash surrender value of corporate-owned life insurance policies of $7 million, lower pension expense and higher interest income, mainly from carrying charges on regulatory items.

*Income tax benefit* decreased $1 million, for the first quarter of 2021 compared to 2020. Nevada Power did not incur tax expense in 2021 primarily due to the recognition of amortization of excess deferred income taxes following regulatory approval effective January 2021. The effective tax rate was 20% in 2020.

**Liquidity and Capital Resources**

As of March 31, 2021, Nevada Power's total net liquidity was as follows (in millions):

| | | |
|---|---|---|
| Cash and cash equivalents | $ | 92 |
| Credit facility | | 400 |
| Total net liquidity | $ | 492 |
| Credit facility: | | |
| Maturity date | | 2022 |

Operating Activities

Net cash flows from operating activities for the three-month periods ended March 31, 2021 and 2020 were $179 million and $79 million, respectively. The change was primarily due to lower payments for fuel and energy costs, the timing of payments for operating costs and lower inventory purchases, partially offset by lower collections from customers.

Investing Activities

Net cash flows from investing activities for the three-month periods ended March 31, 2021 and 2020 were $(106) million and $(111) million, respectively. The change was primarily due to decreased capital expenditures. Refer to "Future Uses of Cash" for further discussion of capital expenditures.

Financing Activities

Net cash flows from financing activities for the three-month periods ended March 31, 2021 and 2020 were $(5) million and $140 million, respectively. The change was primarily due to lower proceeds from the issuance of long-term debt, partially offset by lower repayments of long-term debt.

*Debt Authorizations*

Nevada Power currently has financing authority from the PUCN consisting of the ability to: (1) establish debt issuances limited to a debt ceiling of $3.2 billion (excluding borrowings under Nevada Power's $400 million secured credit facility); and (2) maintain a revolving credit facility of up to $1.3 billion. Nevada Power currently has an effective automatic shelf registration statement with the SEC to issue an indeterminate amount of general and refunding mortgage securities through October 2022.

Future Uses of Cash

Nevada Power has available a variety of sources of liquidity and capital resources, both internal and external, including net cash flows from operating activities, public and private debt offerings, the use of its secured revolving credit facility, 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 regulatory approvals, Nevada Power's credit ratings, investors' judgment of risk 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 forecast capital expenditures, each of which exclude amounts for non-cash equity AFUDC and other non-cash items are as follows (in millions):

| | Three-Month Periods Ended March 31, | | Annual Forecast |
|---|---|---|---|
| | **2020** | **2021** | **2021** |
| Electric distribution | $ 64 | $ 41 | $ 167 |
| Electric transmission | 8 | 13 | 77 |
| Solar generation | — | 1 | 32 |
| Other | 39 | 51 | 181 |
| Total | $ 111 | $ 106 | $ 457 |

Nevada Power's Fourth Amendment to the 2018 Joint IRP proposed an increase in solar generation and electric transmission. Nevada Power has included estimates from its latest IRP filing in its forecast capital expenditures for 2021. These estimates are likely to change as a result of the RFP process and some are still pending PUCN approval. 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 proposed 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. Construction of the project has been approved by the PUCN with the exception of the Northwest substation to Harry Allen substation segment for which approval was limited to design, permitting and land acquisition only. Operating expenditures consist of routine expenditures for transmission and other infrastructure needed to serve existing and expected demand.
- Solar generation investment includes expenditures for a 150 MWs solar photovoltaic facility with an additional 100 MWs capacity of co-located battery storage, known as the Dry Lake generating facility, that will be developed in Clark County, Nevada. Commercial operation is expected by the end of 2023.
- Other investments include both growth projects and operating expenditures consisting of routine expenditures for generation, other operating projects and other infrastructure needed to serve existing and expected demand.

*Contractual Obligations*

As of March 31, 2021, there have been no material changes outside the normal course of business in contractual obligations from the information provided in Item 7 of Nevada Power's Annual Report on Form 10-K for the year ended December 31, 2020.

**Regulatory Matters**

Nevada Power is subject to comprehensive regulation. Refer to "Regulatory Matters" in Berkshire Hathaway Energy's Part I, Item 2 of this Form 10-Q for discussion regarding Nevada Power's 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 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 the EPA and various 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 Nevada Power is unable to predict the impact of the changing laws and regulations on its operations and consolidated financial results. Nevada Power believes it is in material compliance with all applicable laws and regulations.

Refer to "Environmental Laws and Regulations" in Berkshire Hathaway Energy's Part I, Item 2 of this Form 10-Q for additional information regarding environmental laws and regulations.

**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. Estimates are used for, but not limited to, the accounting for the effects of certain types of regulation, derivatives, impairment of long-lived assets, income taxes and revenue recognition - unbilled revenue. For additional discussion of Nevada Power's critical accounting estimates, see Item 7 of Nevada Power's Annual Report on Form 10-K for the year ended December 31, 2020. There have been no significant changes in Nevada Power's assumptions regarding critical accounting estimates since December 31, 2020.

## Sierra Pacific Power Company and its subsidiaries
## Consolidated Financial Section

## PART I

**Item 1. Financial Statements**

## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Sierra Pacific Power Company

**Results of Review of Interim Financial Information**

We have reviewed the accompanying consolidated balance sheet of Sierra Pacific Power Company and subsidiaries ("Sierra Pacific") as of March 31, 2021, the related consolidated statements of operations, changes in shareholder's equity and cash flows for the three-month periods ended March 31, 2021 and 2020, and the related notes (collectively referred to as the "interim financial information"). Based on our reviews, we are not aware of any material modifications that should be made to the accompanying interim financial information for it to be in conformity with accounting principles generally accepted in the United States of America.

We have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the balance sheet of Sierra Pacific as of December 31, 2020, and the related statements of operations, changes in shareholder's equity, and cash flows for the year then ended (not presented herein); and in our report dated February 26, 2021, we expressed an unqualified opinion on those financial statements. In our opinion, the information set forth in the accompanying balance sheet as of December 31, 2020, is fairly stated, in all material respects, in relation to the balance sheet from which it has been derived.

**Basis for Review Results**

This interim financial information is the responsibility of Sierra Pacific's management. We are a public accounting firm registered with the 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 reviews in accordance with standards of the PCAOB. A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the PCAOB, the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

/s/ Deloitte & Touche LLP

Las Vegas, Nevada
April 30, 2021

**SIERRA PACIFIC POWER COMPANY AND SUBSIDIARIES**
**CONSOLIDATED BALANCE SHEETS (Unaudited)**
(Amounts in millions, except share data)

| | As of | |
|---|---|---|
| | March 31, 2021 | December 31, 2020 |
| **ASSETS** | | |
| **Current assets:** | | |
| Cash and cash equivalents | $ 8 | $ 19 |
| Trade receivables, net | 93 | 97 |
| Inventories | 74 | 77 |
| Derivative contracts | 16 | 9 |
| Regulatory assets | 91 | 67 |
| Other current assets | 38 | 36 |
| Total current assets | 320 | 305 |
| | | |
| Property, plant and equipment, net | 3,188 | 3,164 |
| Regulatory assets | 270 | 267 |
| Other assets | 185 | 183 |
| | | |
| **Total assets** | $ 3,963 | $ 3,919 |
| | | |
| **LIABILITIES AND SHAREHOLDER'S EQUITY** | | |
| **Current liabilities:** | | |
| Accounts payable | $ 103 | $ 108 |
| Accrued interest | 11 | 14 |
| Accrued property, income and other taxes | 16 | 14 |
| Short-term debt | 55 | 45 |
| Regulatory liabilities | 28 | 34 |
| Customer deposits | 14 | 15 |
| Other current liabilities | 33 | 25 |
| Total current liabilities | 260 | 255 |
| | | |
| Long-term debt | 1,164 | 1,164 |
| Finance lease obligations | 119 | 121 |
| Regulatory liabilities | 466 | 463 |
| Deferred income taxes | 382 | 374 |
| Other long-term liabilities | 133 | 131 |
| Total liabilities | 2,524 | 2,508 |
| | | |
| Commitments and contingencies (Note 7) | | |
| | | |
| **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 | 329 | 301 |
| Accumulated other comprehensive loss, net | (1) | (1) |
| Total shareholder's equity | 1,439 | 1,411 |
| | | |
| **Total liabilities and shareholder's equity** | $ 3,963 | $ 3,919 |

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

**SIERRA PACIFIC POWER COMPANY AND SUBSIDIARIES**
**CONSOLIDATED STATEMENTS OF OPERATIONS (Unaudited)**
(Amounts in millions)

| | Three-Month Periods Ended March 31, | |
|---|---|---|
| | **2021** | **2020** |
| **Operating revenue:** | | |
| Regulated electric | $ 181 | $ 184 |
| Regulated natural gas | 39 | 48 |
| Total operating revenue | 220 | 232 |
| | | |
| **Operating expenses:** | | |
| Cost of fuel and energy | 82 | 80 |
| Cost of natural gas purchased for resale | 21 | 30 |
| Operations and maintenance | 36 | 42 |
| Depreciation and amortization | 36 | 34 |
| Property and other taxes | 6 | 6 |
| Total operating expenses | 181 | 192 |
| | | |
| **Operating income** | 39 | 40 |
| | | |
| **Other income (expense):** | | |
| Interest expense | (14) | (14) |
| Allowance for equity funds | 1 | 1 |
| Other, net | 6 | 1 |
| Total other income (expense) | (7) | (12) |
| | | |
| **Income before income tax expense** | 32 | 28 |
| Income tax expense | 4 | 3 |
| **Net income** | $ 28 | $ 25 |

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 (Unaudited)**
(Amounts in millions, except shares)

| | Common Stock | | Additional Paid-in Capital | Retained Earnings | Accumulated Other Comprehensive Loss, Net | Total Shareholder's Equity |
|---|---|---|---|---|---|---|
| | Shares | Amount | | | | |
| **Balance, December 31, 2019** | 1,000 | $ — | $ 1,111 | $ 210 | $ (1) | $ 1,320 |
| Net income | — | — | — | 25 | — | 25 |
| **Balance, March 31, 2020** | 1,000 | $ — | $ 1,111 | $ 235 | $ (1) | $ 1,345 |
| | | | | | | |
| **Balance, December 31, 2020** | 1,000 | $ — | $ 1,111 | $ 301 | $ (1) | $ 1,411 |
| Net income | — | — | — | 28 | — | 28 |
| **Balance, March 31, 2021** | 1,000 | $ — | $ 1,111 | $ 329 | $ (1) | $ 1,439 |

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

**SIERRA PACIFIC POWER COMPANY AND SUBSIDIARIES**
**CONSOLIDATED STATEMENTS OF CASH FLOWS (Unaudited)**
(Amounts in millions)

| | Three-Month Periods Ended March 31, | |
|---|---|---|
| | **2021** | **2020** |
| **Cash flows from operating activities:** | | |
| Net income | $ 28 | $ 25 |
| Adjustments to reconcile net income to net cash flows from operating activities: | | |
| Depreciation and amortization | 36 | 34 |
| Allowance for equity funds | (1) | (1) |
| Changes in regulatory assets and liabilities | (13) | (10) |
| Deferred income taxes and amortization of investment tax credits | 4 | (3) |
| Deferred energy | (18) | 14 |
| Amortization of deferred energy | (3) | 4 |
| Other, net | — | 1 |
| Changes in other operating assets and liabilities: | | |
| Trade receivables and other assets | 8 | 1 |
| Inventories | 3 | (3) |
| Accrued property, income and other taxes | (3) | 4 |
| Accounts payable and other liabilities | 1 | (12) |
| Net cash flows from operating activities | 42 | 54 |
| | | |
| **Cash flows from investing activities:** | | |
| Capital expenditures | (61) | (52) |
| Net cash flows from investing activities | (61) | (52) |
| | | |
| **Cash flows from financing activities:** | | |
| Net proceeds from short-term debt | 10 | — |
| Other, net | (2) | (1) |
| Net cash flows from financing activities | 8 | (1) |
| | | |
| **Net change in cash and cash equivalents and restricted cash and cash equivalents** | (11) | 1 |
| **Cash and cash equivalents and restricted cash and cash equivalents at beginning of period** | 26 | 32 |
| **Cash and cash equivalents and restricted cash and cash equivalents at end of period** | $ 15 | $ 33 |

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

SIERRA PACIFIC POWER COMPANY AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

## (1) General

Sierra Pacific Power Company, together with 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").

The unaudited Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") for interim financial information and the United States Securities and Exchange Commission's rules and regulations for Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all of the disclosures required by GAAP for annual financial statements. Management believes the unaudited Consolidated Financial Statements contain all adjustments (consisting only of normal recurring adjustments) considered necessary for the fair presentation of the unaudited Consolidated Financial Statements as of March 31, 2021 and for the three-month periods ended March 31, 2021 and 2020. The Consolidated Statements of Comprehensive Income have been omitted as net income equals comprehensive income for the three-month periods ended March 31, 2021 and 2020. The results of operations for the three-month period ended March 31, 2021 are not necessarily indicative of the results to be expected for the full year.

The preparation of the unaudited Consolidated Financial Statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the unaudited Consolidated Financial Statements and the reported amounts of revenue and expenses during the period. Actual results may differ from the estimates used in preparing the unaudited Consolidated Financial Statements. Note 2 of Notes to Consolidated Financial Statements included in Sierra Pacific's Annual Report on Form 10-K for the year ended December 31, 2020 describes the most significant accounting policies used in the preparation of the unaudited Consolidated Financial Statements. There have been no significant changes in Sierra Pacific's assumptions regarding significant accounting estimates and policies during the three-month period ended March 31, 2021.

## (2) 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 March 31, 2021 and December 31, 2020, consist of funds restricted by the Public Utilities Commission of Nevada ("PUCN") for a certain renewable energy contract. A reconciliation of cash and cash equivalents and restricted cash and cash equivalents as of March 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 | |
|---|---|---|
| | March 31, 2021 | December 31, 2020 |
| Cash and cash equivalents | $ 8 | $ 19 |
| Restricted cash and cash equivalents included in other current assets | 7 | 7 |
| Total cash and cash equivalents and restricted cash and cash equivalents | $ 15 | $ 26 |

## (3) Property, Plant and Equipment, Net

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

| | Depreciable Life | As of March 31, 2021 | As of December 31, 2020 |
|---|---|---|---|
| Utility plant: | | | |
| Electric generation | 25 - 60 years | $ 1,131 | $ 1,130 |
| Electric transmission | 50 - 100 years | 917 | 908 |
| Electric distribution | 20 - 100 years | 1,763 | 1,754 |
| Electric general and intangible plant | 5 - 70 years | 193 | 189 |
| Natural gas distribution | 35 - 70 years | 431 | 429 |
| Natural gas general and intangible plant | 5 - 70 years | 15 | 15 |
| Common general | 5 - 70 years | 357 | 355 |
| Utility plant | | 4,807 | 4,780 |
| Accumulated depreciation and amortization | | (1,783) | (1,755) |
| Utility plant, net | | 3,024 | 3,025 |
| Other non-regulated, net of accumulated depreciation and amortization | 70 years | 2 | 2 |
| Plant, net | | 3,026 | 3,027 |
| Construction work-in-progress | | 162 | 137 |
| Property, plant and equipment, net | | $ 3,188 | $ 3,164 |

## (4) Income Taxes

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:

| | Three-Month Periods Ended March 31, 2021 | Three-Month Periods Ended March 31, 2020 |
|---|---|---|
| Federal statutory income tax rate | 21 % | 21 % |
| Effects of ratemaking | (10) | (8) |
| Other | 2 | (2) |
| Effective income tax rate | 13 % | 11 % |

Effects of ratemaking is primarily attributable to the recognition of excess deferred income taxes related to the 2017 Tax Cuts and Jobs Act pursuant to an order issued by the PUCN effective January 1, 2020.

## (5) 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. 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 (in millions):

| | As of | |
|---|---|---|
| | March 31, 2021 | December 31, 2020 |
| **Qualified Pension Plan:** | | |
| Other non-current assets | $ 27 | $ 26 |
| | | |
| **Non-Qualified Pension Plans:** | | |
| Other current liabilities | (1) | (1) |
| Other long-term liabilities | (8) | (8) |
| | | |
| **Other Postretirement Plans:** | | |
| Other long-term liabilities | (14) | (13) |

## (6) 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 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 March 31, 2021** | | | | |
| **Assets:** | | | | |
| Commodity derivatives | $ — | $ — | $ 16 | $ 16 |
| Money market mutual funds[(1)] | 5 | — | — | 5 |
| | $ 5 | $ — | $ 16 | $ 21 |
| | | | | |
| **Liabilities - commodity derivatives** | $ — | $ — | $ (4) | $ (4) |
| | | | | |
| **As of December 31, 2020** | | | | |
| **Assets:** | | | | |
| Commodity derivatives | $ — | $ — | $ 9 | $ 9 |
| Money market mutual funds[(1)] | 17 | — | — | 17 |
| | $ 17 | $ — | $ 9 | $ 26 |
| | | | | |
| **Liabilities - commodity derivatives** | $ — | $ — | $ (2) | $ (2) |

(1) Amounts are included in cash and cash equivalents on the Consolidated Balance Sheets. The fair value of these money market mutual funds approximates cost.

Sierra Pacific's investments in money market mutual funds and investment funds are stated at fair value. When available, a readily observable quoted market price or net asset value of an identical security in an active market is used to record the fair value.

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 carrying value of Sierra Pacific'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 Sierra Pacific's long-term debt (in millions):

| | As of March 31, 2021 | | As of December 31, 2020 | |
|---|---|---|---|---|
| | Carrying Value | Fair Value | Carrying Value | Fair Value |
| Long-term debt | $ 1,164 | $ 1,312 | $ 1,164 | $ 1,358 |

## (7) Commitments and Contingencies

*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 consolidated financial results.

*Environmental Laws and Regulations*

Sierra Pacific is subject to federal, state and local 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 Sierra Pacific's current and future operations. Sierra Pacific believes it is in material compliance with all applicable laws and regulations.

## (8) Revenue from Contracts with Customers

The following table summarizes Sierra Pacific's revenue from contracts with customers ("Customer Revenue") by customer class, including a reconciliation to Sierra Pacific's reportable segment information included in Note 9 (in millions):

| | Three-Month Periods Ended March 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2021 | | | 2020 | | |
| | Electric | Natural Gas | Total | Electric | Natural Gas | Total |
| Customer Revenue: | | | | | | |
| Retail: | | | | | | |
| Residential | $ 71 | $ 25 | $ 96 | $ 69 | $ 30 | $ 99 |
| Commercial | 54 | 10 | 64 | 57 | 13 | 70 |
| Industrial | 39 | 3 | 42 | 41 | 4 | 45 |
| Other | 1 | — | 1 | 1 | — | 1 |
| Total fully bundled | 165 | 38 | 203 | 168 | 47 | 215 |
| Distribution only service | 1 | — | 1 | 1 | — | 1 |
| Total retail | 166 | 38 | 204 | 169 | 47 | 216 |
| Wholesale, transmission and other | 15 | — | 15 | 14 | — | 14 |
| Total Customer Revenue | 181 | 38 | 219 | 183 | 47 | 230 |
| Other revenue | — | 1 | 1 | 1 | 1 | 2 |
| Total revenue | $ 181 | $ 39 | $ 220 | $ 184 | $ 48 | $ 232 |

## (9) 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):

| | Three-Month Periods Ended March 31, | |
|---|---|---|
| | **2021** | **2020** |
| **Operating revenue:** | | |
| Regulated electric | $ 181 | $ 184 |
| Regulated natural gas | 39 | 48 |
| Total operating revenue | $ 220 | $ 232 |
| | | |
| **Operating income:** | | |
| Regulated electric | $ 31 | $ 33 |
| Regulated natural gas | 8 | 7 |
| Total operating income | 39 | 40 |
| Interest expense | (14) | (14) |
| Allowance for equity funds | 1 | 1 |
| Other, net | 6 | 1 |
| **Income before income tax expense** | $ 32 | $ 28 |

| | As of | |
|---|---|---|
| | **March 31, 2021** | **December 31, 2020** |
| **Assets:** | | |
| Regulated electric | $ 3,589 | $ 3,540 |
| Regulated natural gas | 348 | 342 |
| Other(1) | 26 | 37 |
| Total assets | $ 3,963 | $ 3,919 |

(1) Consists principally of cash and cash equivalents not included in either the regulated electric or regulated natural gas segments.

## Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following is management's discussion and analysis of certain significant factors that have affected the consolidated financial condition and results of operations of Sierra Pacific during the periods included herein. Explanations include management's best estimate of the impact of weather, customer growth, usage trends and other factors. This discussion should be read in conjunction with Sierra Pacific's historical unaudited Consolidated Financial Statements and Notes to Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q. Sierra Pacific's actual results in the future could differ significantly from the historical results.

### Results of Operations for the First Quarter of 2021 and 2020

Overview

Net income for the first quarter of 2021 was $28 million, an increase of $3 million, or 12%, compared to 2020 primarily due to $6 million of lower operations and maintenance expenses, mainly due to lower plant operations and maintenance expenses and a reduction to the accrual for earning sharing, and $5 million of higher other, net, mainly due to higher cash surrender value of corporate-owned life insurance policies and lower pension costs, partially offset by $5 million of lower electric utility margin, mainly from lower revenue recognized due to a favorable regulatory decision.

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 customers through regulatory recovery mechanisms and as a result, changes in Sierra Pacific's expenses 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 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 (in millions):

| | First Quarter | | | |
|---|---|---|---|---|
| | 2021 | 2020 | Change | |
| **Electric utility margin:** | | | | |
| Operating revenue | $ 181 | $ 184 | $ (3) | (2)% |
| Cost of fuel and energy | 82 | 80 | 2 | 3 |
| **Electric utility margin** | 99 | 104 | (5) | (5) |
| | | | | |
| **Natural gas utility margin:** | | | | |
| Operating revenue | 39 | 48 | (9) | (19)% |
| Natural gas purchased for resale | 21 | 30 | (9) | (30) |
| **Natural gas utility margin** | 18 | 18 | — | — |
| | | | | |
| **Utility margin** | 117 | 122 | (5) | (4)% |
| | | | | |
| Operations and maintenance | 36 | 42 | (6) | (14)% |
| Depreciation and amortization | 36 | 34 | 2 | 6 |
| Property and other taxes | 6 | 6 | — | — |
| **Operating income** | $ 39 | $ 40 | $ (1) | (3)% |

Electric Utility Margin

A comparison of key operating results related to electric utility margin is as follows for the quarters ended March 31:

| | First Quarter | | | |
|---|---|---|---|---|
| | 2021 | 2020 | Change | |
| **Utility margin (in millions):** | | | | |
| Operating revenue | $ 181 | $ 184 | $ (3) | (2)% |
| Cost of fuel and energy | 82 | 80 | 2 | 3 |
| Utility margin | $ 99 | $ 104 | $ (5) | (5)% |
| | | | | |
| **Sales (GWhs):** | | | | |
| Residential | 671 | 635 | 36 | 6 % |
| Commercial | 677 | 701 | (24) | (3) |
| Industrial | 897 | 909 | (12) | (1) |
| Other | 4 | 4 | — | — |
| Total fully bundled[1] | 2,249 | 2,249 | — | — |
| Distribution only service | 397 | 412 | (15) | (4) |
| Total retail | 2,646 | 2,661 | (15) | (1) |
| Wholesale | 175 | 193 | (18) | (9) |
| Total GWhs sold | 2,821 | 2,854 | (33) | (1)% |
| | | | | |
| **Average number of retail customers (in thousands)** | 363 | 356 | 7 | 2 % |
| | | | | |
| **Average revenue per MWh:** | | | | |
| Retail - fully bundled[1] | $ 73.17 | $ 74.76 | $ (1.59) | (2)% |
| Wholesale | $ 60.18 | $ 49.05 | $ 11.13 | 23 % |
| | | | | |
| **Heating degree days** | 2,198 | 2,066 | 132 | 6 % |
| | | | | |
| **Sources of energy (GWhs)[2]:** | | | | |
| Natural gas | 1,082 | 1,215 | (133) | (11)% |
| Coal | 29 | 66 | (37) | (56) |
| Renewables[3] | 6 | 6 | — | — |
| Total energy generated | 1,117 | 1,287 | (170) | (13) |
| Energy purchased | 1,373 | 1,325 | 48 | 4 |
| Total | 2,490 | 2,612 | (122) | (5)% |
| | | | | |
| **Average cost of energy per MWh[4]:** | | | | |
| Energy generated | $ 25.23 | $ 26.53 | $ (1.30) | (5)% |
| Energy purchased | $ 38.93 | $ 34.96 | $ 3.97 | 11 % |

(1) Fully bundled includes sales to customers for combined energy, transmission and distribution services.

(2) GWh amounts are net of energy used by the related generating facilities.

(3) Includes the Fort Churchill Solar Array which is under lease by Sierra Pacific.

(4) The average cost of energy per MWh includes the cost of fuel, purchased power and deferrals and does not include other costs.

Natural Gas Utility Margin

A comparison of key operating results related to natural gas utility margin is as follows for the quarters ended March 31:

| | First Quarter | | | |
|---|---|---|---|---|
| | 2021 | 2020 | Change | |
| **Utility margin (in millions):** | | | | |
| Operating revenue | $ 39 | $ 48 | $ (9) | (19)% |
| Natural gas purchased for resale | 21 | 30 | (9) | (30) |
| Utility margin | $ 18 | $ 18 | $ — | — % |
| **Sold (000's Dths):** | | | | |
| Residential | 4,658 | 4,386 | 272 | 6 % |
| Commercial | 2,304 | 2,167 | 137 | 6 |
| Industrial | 745 | 653 | 92 | 14 |
| Total retail | 7,707 | 7,206 | 501 | 7 % |
| **Average number of retail customers (in thousands)** | 176 | 173 | 3 | 2 % |
| **Average revenue per retail Dth sold** | $ 5.03 | $ 6.58 | $ (1.55) | (24)% |
| **Heating degree days** | 2,198 | 2,066 | 132 | 6 % |
| **Average cost of natural gas per retail Dth sold** | $ 2.73 | $ 4.22 | $ (1.49) | (35)% |

Quarter Ended March 31, 2021 Compared to Quarter Ended March 31, 2020

*Electric utility margin* decreased $5 million, or 5%, for the first quarter of 2021 compared to 2020 primarily due to:

- $3 million in lower revenue recognized due to a favorable regulatory decision and
- $1 million due to price impacts from changes in sales mix. Retail customer volumes, including distribution only service customers, decreased 0.6% primarily due to the impacts of COVID-19, which resulted in lower distribution only service, commercial and industrial customer usage and higher residential customer usage, offset by the favorable impacts of weather.

*Operations and maintenance* decreased $6 million, or 14%, for the first quarter of 2021 compared to 2020 primarily due to lower plant operations and maintenance expenses, a reduction to the accrual for earning sharing and lower regulatory amortizations.

*Depreciation and amortization* increased $2 million, or 6%, for the first quarter of 2021 compared to 2020 primarily due to regulatory amortizations and higher plant in service.

*Other, net* increased $5 million for the first quarter of 2021 compared to 2020 primarily due to higher cash surrender value of corporate-owned life insurance policies and lower pension costs.

*Income tax expense* increased $1 million, or 33%, for the first quarter of 2021 compared to 2020. The effective tax rate was 13% in 2021 and 11% in 2020 and increased primarily due to higher pre-tax income.

**Liquidity and Capital Resources**

As of March 31, 2021, Sierra Pacific's total net liquidity was as follows (in millions):

| | | |
|---|---|---|
| Cash and cash equivalents | $ | 8 |
| | | |
| Credit facility | | 250 |
| Less - | | |
| Short-term debt | | (55) |
| Net credit facility | | 195 |
| | | |
| Total net liquidity | $ | 203 |
| Credit facility: | | |
| Maturity date | | 2022 |

Operating Activities

Net cash flows from operating activities for the three-month periods ended March 31, 2021 and 2020 were $42 million and $54 million, respectively. The change was primarily due to higher payments for fuel and energy costs and lower collections from customers partially offset by lower inventory purchases, the timing of payments for operating costs and increased collections of customer advances.

Investing Activities

Net cash flows from investing activities for the three-month periods ended March 31, 2021 and 2020 were $(61) million and $(52) million, respectively. The change was primarily due to increased capital expenditures. Refer to "Future Uses of Cash" for further discussion of capital expenditures.

Financing Activities

Net cash flows from financing activities for the three-month periods ended March 31, 2021 and 2020 were $8 million and $(1) million, respectively. The change was primarily due to higher proceeds from short-term debt.

*Debt Authorizations*

Sierra Pacific currently has financing authority from the PUCN consisting of the ability to: (1) establish debt issuances limited to a debt ceiling of $1.6 billion (excluding borrowings under Sierra Pacific's $250 million secured credit facility); and (2) maintain a revolving credit facility of up to $600 million.

Future Uses of Cash

Sierra Pacific has available a variety of sources of liquidity and capital resources, both internal and external, including net cash flows from operating activities, public and private debt offerings, the use of its secured revolving credit facility, 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 regulatory approvals, Sierra Pacific's credit ratings, investors' judgment of risk 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 forecast capital expenditures, each of which exclude amounts for non-cash equity AFUDC and other non-cash items are as follows (in millions):

| | Three-Month Periods Ended March 31, | | Annual Forecast |
|---|---|---|---|
| | **2020** | **2021** | **2021** |
| Electric distribution | $ 37 | $ 20 | $ 126 |
| Electric transmission | 8 | 16 | 124 |
| Solar generation | — | — | 18 |
| Other | 7 | 25 | 129 |
| Total | $ 52 | $ 61 | $ 397 |

Sierra Pacific's Fourth Amendment to the 2018 Joint IRP proposed an increase in electric transmission. Sierra Pacific has included estimates from its latest IRP filing in its forecast capital expenditures for 2021. These estimates are likely to change as a result of the RFP process and some are still pending PUCN approval. 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 proposed to build 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 Comstock Meadows substations. Construction of the project has been approved by the PUCN with the exception of the Ft. Churchill substation to the Robinson Summit substation segment for which conditional approval was limited to design, permitting and land acquisition only. Operating expenditures consist of routine expenditures for transmission and other infrastructure needed to serve existing and expected demand.
- Other investments include both growth projects and operating expenditures consisting of routine expenditures for generation, other operating projects and other infrastructure needed to serve existing and expected demand.

*Contractual Obligations*

As of March 31, 2021, there have been no material changes outside the normal course of business in contractual obligations from the information provided in Item 7 of Sierra Pacific's Annual Report on Form 10-K for the year ended December 31, 2020.

**Regulatory Matters**

Sierra Pacific is subject to comprehensive regulation. Refer to "Regulatory Matters" in Berkshire Hathaway Energy's Part I, Item 2 of this Form 10-Q for discussion regarding Sierra Pacific's 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 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 the EPA and various 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 Sierra Pacific is unable to predict the impact of the changing laws and regulations on its operations and consolidated financial results. Sierra Pacific believes it is in material compliance with all applicable laws and regulations.

Refer to "Environmental Laws and Regulations" in Berkshire Hathaway Energy's Part I, Item 2 of this Form 10-Q for additional information regarding environmental laws and regulations.

**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. Estimates are used for, but not limited to, the accounting for the effects of certain types of regulation, derivatives, impairment of long-lived assets, income taxes and revenue recognition - unbilled revenue. For additional discussion of Sierra Pacific's critical accounting estimates, see Item 7 of Sierra Pacific's Annual Report on Form 10-K for the year ended December 31, 2020. There have been no significant changes in Sierra Pacific's assumptions regarding critical accounting estimates since December 31, 2020.

**Eastern Energy Gas Holdings, LLC and its subsidiaries**
**Consolidated Financial Section**

PART I

**Item 1. Financial Statements**

## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Eastern Energy Gas Holdings, LLC

**Results of Review of Interim Financial Information**

We have reviewed the accompanying consolidated balance sheet of Eastern Energy Gas Holdings, LLC and subsidiaries ("Eastern Energy Gas") as of March 31, 2021, the related consolidated statements of operations, comprehensive income, changes in equity and cash flows for the three-month periods ended March 31, 2021 and 2020, and the related notes (collectively referred to as the "interim financial information"). Based on our reviews, we are not aware of any material modifications that should be made to the accompanying interim financial information for it to be in conformity with accounting principles generally accepted in the United States of America.

We have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheet of Eastern Energy Gas as of December 31, 2020, and the related consolidated statements of operations, comprehensive income, changes in equity, and cash flows for the year then ended (not presented herein); and in our report dated February 26, 2021, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying consolidated balance sheet as of December 31, 2020, is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

**Basis for Review Results**

This interim financial information is the responsibility of Eastern Energy Gas' management. We are a public accounting firm registered with the 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 reviews in accordance with standards of the PCAOB. A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the PCAOB, the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

/s/ Deloitte & Touche LLP

Richmond, Virginia
April 30, 2021

**EASTERN ENERGY GAS HOLDINGS, LLC AND SUBSIDIARIES**
**CONSOLIDATED BALANCE SHEETS (Unaudited)**
(Amounts in millions)

| | As of | |
|---|---|---|
| | March 31, 2021 | December 31, 2020 |
| **ASSETS** | | |
| **Current assets:** | | |
| Cash and cash equivalents | $ 106 | $ 35 |
| Restricted cash and cash equivalents | 9 | 13 |
| Trade receivables, net | 158 | 177 |
| Receivables from affiliates | 263 | 139 |
| Other receivables | 44 | 51 |
| Inventories | 120 | 119 |
| Other current assets | 145 | 122 |
| Total current assets | 845 | 656 |
| | | |
| Property, plant and equipment, net | 10,099 | 10,144 |
| Goodwill | 1,286 | 1,286 |
| Investments | 262 | 244 |
| Other assets | 240 | 291 |
| | | |
| **Total assets** | $ 12,732 | $ 12,621 |

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

**EASTERN ENERGY GAS HOLDINGS, LLC AND SUBSIDIARIES**
**CONSOLIDATED BALANCE SHEETS (Unaudited) (continued)**
(Amounts in millions)

| | As of | |
|---|---|---|
| | **March 31, 2021** | **December 31, 2020** |
| **LIABILITIES AND EQUITY** | | |
| **Current liabilities:** | | |
| Accounts payable | $ 59 | $ 71 |
| Accounts payable to affiliates | 57 | 39 |
| Accrued interest | 54 | 19 |
| Accrued property, income and other taxes | 60 | 29 |
| Notes payable | — | 9 |
| Current portion of long-term debt | 500 | 500 |
| Other current liabilities | 127 | 147 |
| Total current liabilities | 857 | 814 |
| | | |
| Long-term debt | 3,914 | 3,925 |
| Regulatory liabilities | 668 | 669 |
| Other long-term liabilities | 215 | 218 |
| Total liabilities | 5,654 | 5,626 |
| | | |
| Commitments and contingencies (Note 8) | | |
| | | |
| **Equity:** | | |
| Member's equity: | | |
| Membership interests | 3,035 | 2,957 |
| Accumulated other comprehensive loss, net | (45) | (53) |
| Total member's equity | 2,990 | 2,904 |
| Noncontrolling interests | 4,088 | 4,091 |
| Total equity | 7,078 | 6,995 |
| | | |
| **Total liabilities and equity** | $ 12,732 | $ 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 (Unaudited)**
(Amounts in millions)

| | Three-Month Periods Ended March 31, | |
|---|---|---|
| | **2021** | **2020** |
| **Operating revenue** | $ 486 | $ 556 |
| **Operating expenses:** | | |
| Cost of gas | — | 8 |
| Operations and maintenance | 124 | 168 |
| Depreciation and amortization | 80 | 93 |
| Property and other taxes | 39 | 39 |
| Total operating expenses | 243 | 308 |
| **Operating income** | 243 | 248 |
| **Other income (expense):** | | |
| Interest expense | (44) | (58) |
| Allowance for equity funds | 2 | 5 |
| Interest and dividend income | — | 30 |
| Other, net | 1 | 14 |
| Total other income (expense) | (41) | (9) |
| **Income before income tax expense and equity income** | 202 | 239 |
| Income tax expense | 27 | 52 |
| Equity income | 16 | 15 |
| **Net income** | 191 | 202 |
| Net income attributable to noncontrolling interests | 102 | 33 |
| **Net income attributable to Eastern Energy Gas** | $ 89 | $ 169 |

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

**EASTERN ENERGY GAS HOLDINGS, LLC AND SUBSIDIARIES**
**CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (Unaudited)**
(Amounts in millions)

| | Three-Month Periods Ended March 31, | |
|---|---|---|
| | **2021** | **2020** |
| Net income | $ 191 | $ 202 |
| | | |
| Other comprehensive income (loss), net of tax: | | |
| Unrecognized amounts on retirement benefits, net of tax of $— and $1 | 2 | 1 |
| Unrealized gains (losses) on cash flow hedges, net of tax of $3 and $(30) | 10 | (85) |
| Total other comprehensive income (loss), net of tax | 12 | (84) |
| | | |
| Comprehensive income | 203 | 118 |
| Comprehensive income attributable to noncontrolling interests | 106 | 33 |
| Comprehensive income attributable to Eastern Energy Gas | $ 97 | $ 85 |

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 (Unaudited)
(Amounts in millions)

| | Membership Interests | Accumulated Other Comprehensive Loss, Net | Noncontrolling Interests | Total Equity |
|---|---|---|---|---|
| **Balance, December 31, 2019** | $ 9,031 | $ (187) | $ 1,385 | $ 10,229 |
| Net income | 169 | — | 33 | 202 |
| Other comprehensive loss | — | (84) | — | (84) |
| Distributions | (232) | — | (37) | (269) |
| **Balance, March 31, 2020** | $ 8,968 | $ (271) | $ 1,381 | $ 10,078 |
| | | | | |
| **Balance, December 31, 2020** | $ 2,957 | $ (53) | $ 4,091 | $ 6,995 |
| Net income | 89 | — | 102 | 191 |
| Other comprehensive income | — | 8 | 4 | 12 |
| Contributions | 11 | — | — | 11 |
| Distributions | (22) | — | (109) | (131) |
| **Balance, March 31, 2021** | $ 3,035 | $ (45) | $ 4,088 | $ 7,078 |

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

**EASTERN ENERGY GAS HOLDINGS, LLC AND SUBSIDIARIES**
**CONSOLIDATED STATEMENTS OF CASH FLOWS (Unaudited)**
(Amounts in millions)

| | Three-Month Periods Ended March 31, | |
|---|---|---|
| | **2021** | **2020** |
| **Cash flows from operating activities:** | | |
| Net income | $ 191 | $ 202 |
| Adjustments to reconcile net income to net cash flows from operating activities: | | |
| Depreciation and amortization | 80 | 93 |
| Allowance for equity funds | (2) | (5) |
| Equity income, net of distributions | (5) | (1) |
| Changes in regulatory assets and liabilities | 6 | 7 |
| Deferred income taxes | 30 | 15 |
| Other, net | — | (1) |
| Changes in other operating assets and liabilities: | | |
| Trade receivables and other assets | (56) | 357 |
| Derivative collateral, net | 2 | 9 |
| Pension and other postretirement benefit plans | — | (18) |
| Accrued property, income and other taxes | (25) | (17) |
| Accounts payable and other liabilities | 20 | 26 |
| Net cash flows from operating activities | 241 | 667 |
| | | |
| **Cash flows from investing activities:** | | |
| Capital expenditures | (55) | (76) |
| Loans to affiliates | — | (262) |
| Other, net | (1) | (4) |
| Net cash flows from investing activities | (56) | (342) |
| | | |
| **Cash flows from financing activities:** | | |
| Net repayments of short-term debt | — | (32) |
| Repayment of notes payable, net | (9) | (5) |
| Distributions | (109) | (269) |
| Net cash flows from financing activities | (118) | (306) |
| | | |
| **Net change in cash and cash equivalents and restricted cash and cash equivalents** | 67 | 19 |
| **Cash and cash equivalents and restricted cash and cash equivalents at beginning of period** | 48 | 39 |
| **Cash and cash equivalents and restricted cash and cash equivalents at end of period** | $ 115 | $ 58 |

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

## (1) General

Eastern Energy Gas Holdings, LLC and its subsidiaries ("Eastern Energy Gas") is a holding company that 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.

In July 2020, Dominion Energy, Inc. ("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 Berkshire Hathaway Energy Company ("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 acquisition of substantially all of the natural gas transmission and storage business of DEI and Dominion Energy Questar Corporation, exclusive of Dominion Energy Questar Pipeline, LLC and related entities (the "Questar Pipeline Group") (the "GT&S Transaction") and the proposed sale of the Questar Pipeline Group by DEI to BHE pursuant to a purchase and sale agreement entered into on October 5, 2020 ("Q-Pipe Transaction"). The Q-Pipe Transaction is currently anticipated to close in the first half of 2021, contingent on clearance or approval under the Hart-Scott-Rodino Act, and other customary closing and regulatory conditions. 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. On November 1, 2020, BHE completed 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").

The unaudited Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") for interim financial information and the United States Securities and Exchange Commission's rules and regulations for Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all of the disclosures required by GAAP for annual financial statements. Management believes the unaudited Consolidated Financial Statements contain all adjustments (consisting only of normal recurring adjustments) considered necessary for the fair presentation of the unaudited Consolidated Financial Statements as of March 31, 2021 and for the three-month periods ended March 31, 2021 and 2020. The results of operations for the three-month periods ended March 31, 2021 are not necessarily indicative of the results to be expected for the full year.

The preparation of the unaudited Consolidated Financial Statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the unaudited Consolidated Financial Statements and the reported amounts of revenue and expenses during the period. Actual results may differ from the estimates used in preparing the unaudited Consolidated Financial Statements. Note 2 of Notes to Consolidated Financial Statements included in Eastern Energy Gas' Annual Report on Form 10-K for the year ended December 31, 2020 describes the most significant accounting policies used in the preparation of the unaudited Consolidated Financial Statements. There have been no significant changes in Eastern Energy Gas' assumptions regarding significant accounting estimates and policies during the three-month period ended March 31, 2021.

## (2) Property, Plant and Equipment, Net

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

| | | As of | |
|---|---|---|---|
| | Depreciable Life | March 31, 2021 | December 31, 2020 |
| **Utility Plant:** | | | |
| Interstate natural gas pipeline assets | 24 - 43 years | $ 8,385 | $ 8,382 |
| Intangible plant | 5 - 10 years | 114 | 115 |
| Utility plant in service | | 8,499 | 8,497 |
| Accumulated depreciation and amortization | | (2,792) | (2,759) |
| Utility plant in service, net | | 5,707 | 5,738 |
| | | | |
| **Nonutility Plant:** | | | |
| LNG facility | 40 years | 4,460 | 4,454 |
| Intangible plant | 14 years | 25 | 25 |
| Nonutility plant in service | | 4,485 | 4,479 |
| Accumulated depreciation and amortization | | (320) | (283) |
| Nonutility plant in service, net | | 4,165 | 4,196 |
| | | | |
| Plant, net | | 9,872 | 9,934 |
| Construction work- in-progress | | 227 | 210 |
| Property, plant and equipment, net | | $ 10,099 | $ 10,144 |

Construction work-in-progress includes $211 million and $196 million as of March 31, 2021 and December 31, 2020, respectively, related to the construction of utility plant.

## (3) Investments and Restricted Cash and Cash Equivalents

Investments and restricted cash and cash equivalents consists of the following (in millions):

| | As of | |
|---|---|---|
| | March 31, 2021 | December 31, 2020 |
| **Investments:** | | |
| Investment funds | $ 12 | $ — |
| | | |
| **Equity method investments:** | | |
| Iroquois | 250 | 244 |
| | | |
| Total investments | 262 | 244 |
| | | |
| **Restricted cash and cash equivalents:** | | |
| Customer deposits | 9 | 13 |
| Total restricted cash and cash equivalents | 9 | 13 |
| | | |
| Total investments and restricted cash and cash equivalents | $ 271 | $ 257 |
| | | |
| Reflected as: | | |
| Current assets | $ 9 | $ 13 |
| Noncurrent assets | 262 | 244 |
| Total investments and restricted cash and cash equivalents | $ 271 | $ 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 March 31, 2021 and December 31, 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 received distributions from its investments of $10 million and $15 million for the three-month periods ended March 31, 2021 and 2020, respectively.

*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 March 31, 2021 and December 31, 2020 consist substantially of customer deposits as allowed under the FERC gas tariffs. A reconciliation of cash and cash equivalents and restricted cash and cash equivalents as of March 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 | |
|---|---|---|
| | March 31, 2021 | December 31, 2020 |
| Cash and cash equivalents | $ 106 | $ 35 |
| Restricted cash and cash equivalents | 9 | 13 |
| Total cash and cash equivalents and restricted cash and cash equivalents | $ 115 | $ 48 |

**(4) Regulatory Matters**

*Eastern Gas Transmission and Storage, Inc.*

In July 2017, the FERC audit staff communicated to Eastern Gas Transmission and Storage, Inc. ("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 of $129 million ($94 million after-tax) for the year ended December 31, 2018 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 allowance for funds used during construction. As a condition of the December 2020 ruling, EGTS will file its proposed accounting entries and supporting documentation with the FERC by the second quarter of 2021; however, EGTS does not expect a material change from the charge recognized.

*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, 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 $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.

**(5) Income Taxes**

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:

| | Three-Month Periods Ended March 31, | |
|---|---|---|
| | 2021 | 2020 |
| Federal statutory income tax rate | 21 % | 21 % |
| State income tax, net of federal income tax benefit | 3 | 3 |
| Equity interest | 2 | 1 |
| Effects of ratemaking | (1) | (1) |
| Absence of noncontrolling interest | (11) | (3) |
| Other, net | (1) | 1 |
| Effective income tax rate | 13 % | 22 % |

Absence of tax on noncontrolling interest is attributable to Eastern Energy Gas' ownership in Cove Point. The GT&S Transaction resulted in a change of noncontrolling interest to 75% as of March 31, 2021 from 25% as of March 31, 2020.

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. Subsequent to the GT&S Transaction, Eastern Energy Gas, as a subsidiary of BHE, is included in Berkshire Hathaway's United States federal income tax return. Consistent with established regulatory practice, Eastern Energy Gas' provisions for income tax have been computed on a stand-alone basis, and substantially all of its currently payable or receivable income tax is remitted to or received from BHE. Eastern Energy Gas made no cash payments for income tax to BHE for the three-month period ended March 31, 2021.

**(6) Employee 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. Also prior to the GT&S Transaction, pension benefits for Eastern Energy Gas employees represented by collective bargaining units were provided by a separate plan that provides benefits to employees of both EGTS and Hope Gas, Inc. ("Hope"). Subsequent to the GT&S Transaction, Eastern Energy Gas employees are covered by the MidAmerican Energy Company ("MidAmerican Energy") Pension Plan, similar to the DEI plan.

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. Also prior to the GT&S Transaction, retiree health 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. Subsequent to the GT&S Transaction, Eastern Energy Gas employees are covered by the MidAmerican Energy Retiree Health and Welfare plan, similar to the DEI plan.

Net periodic benefit cost (credit) for the pension and other postretirement benefit plans included the following components (in millions):

| | Three-Month Periods Ended March 31, | |
|---|---|---|
| | 2021 | 2020 |
| **Pension:** | | |
| Service cost | $ — | $ 1 |
| Interest cost | — | 3 |
| Expected return on plan assets | — | (14) |
| Net amortization | — | 2 |
| Net periodic benefit cost (credit) | $ — | $ (8) |
| | | |
| **Other Postretirement:** | | |
| Service cost | $ — | $ 1 |
| Interest cost | — | 1 |
| Expected return on plan assets | — | (5) |
| Net amortization | — | (1) |
| Net periodic benefit cost (credit) | $ — | $ (4) |

**(7) 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 March 31, 2021** | | | | |
| **Assets:** | | | | |
| Foreign currency exchange rate derivatives | $ — | $ 12 | $ — | $ 12 |
| Money market mutual funds[(1)] | 71 | — | — | 71 |
| Investment funds | 12 | — | — | 12 |
| | $ 83 | $ 12 | $ — | $ 95 |
| | | | | |
| **Liabilities:** | | | | |
| Foreign currency exchange rate derivatives | $ — | $ (1) | $ — | $ (1) |
| Interest rate derivatives | — | (3) | — | (3) |
| | $ — | $ (4) | $ — | $ (4) |
| | | | | |
| **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) |

(1) Amounts are included in cash and cash equivalents on the Consolidated Balance Sheets. The fair value of these money market mutual funds approximates cost.

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 Balance Sheets. 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 (in millions):

| | As of March 31, 2021 | | As of December 31, 2020 | |
|---|---|---|---|---|
| | Carrying Value | Fair Value | Carrying Value | Fair Value |
| Long-term debt | $ 4,414 | $ 4,744 | $ 4,425 | $ 5,012 |

## (8) Commitments and Contingencies

*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.

*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. Eastern Energy Gas believes it is in material compliance with all applicable laws and regulations.

## (9) Revenue from Contracts with Customers

The following table summarizes Eastern Energy Gas' energy products and services revenue by regulated and nonregulated (in millions):

| | Three-Month Periods Ended March 31, | |
|---|---|---|
| | 2021 | 2020 |
| Customer Revenue: | | |
| Regulated: | | |
| Gas transportation and storage | $ 279 | $ 344 |
| Wholesale | 17 | 2 |
| Other | — | 1 |
| Total regulated | 296 | 347 |
| Nonregulated | 190 | 208 |
| Total Customer Revenue | 486 | 555 |
| Other revenue | — | 1 |
| Total operating revenue | $ 486 | $ 556 |

*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 March 31, 2021 (in millions):

| | Performance obligations expected to be satisfied | | |
|---|---|---|---|
| | Less than 12 months | More than 12 months | Total |
| Eastern Energy Gas | $ 1,564 | $ 16,115 | $ 17,679 |

**(10) 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 tax (in millions):

| | Unrecognized Amounts On Retirement Benefits | Unrealized Losses on Cash Flow Hedges | Noncontrolling Interests | Accumulated Other Comprehensive Loss, Net |
|---|---|---|---|---|
| **Balance, December 31, 2019** | $ (106) | $ (81) | $ — | $ (187) |
| Other comprehensive income (loss) | 1 | (85) | — | (84) |
| **Balance, March 31, 2020** | $ (105) | $ (166) | $ — | $ (271) |
| | | | | |
| **Balance, December 31, 2020** | $ (12) | $ (51) | $ 10 | $ (53) |
| Other comprehensive income (loss) | 2 | 10 | (4) | 8 |
| **Balance, March 31, 2021** | $ (10) | $ (41) | $ 6 | $ (45) |

**(11) 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.

In November 2019, 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 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 $3 million and $4 million for the three-month periods ended March 31, 2021 and 2020, respectively. Eastern Energy Gas' Consolidated Balance Sheets included amounts due to Carolina Gas Services of $26 million and $22 million as of March 31, 2021 and December 31, 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 $7 million for the three-month period ended March 31, 2020. 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 $31 million for the three-month period ended March 31, 2020. 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.

**(12) 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 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. Eastern Energy Gas participated in certain DEI benefit plans as described in Note 6.

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 three-month period ended March 31, 2020 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 three-month period ended March 31, 2020 (in millions):

| | | |
|---|---|---|
| Sales of natural gas and transportation and storage services | $ | 64 |
| Purchases of natural gas and transportation and storage services | | 3 |
| Services provided by related parties(1) | | 43 |
| Services provided to related parties(2) | | 32 |

(1) Includes capitalized expenditures of $3 million.

(2) Amount primarily attributable to Atlantic Coast Pipeline, LLC, a related-party VIE prior to the GT&S Transaction.

Interest income related to Eastern Energy Gas' affiliated notes receivable from DEI was $11 million for the three-month period ended March 31, 2020.

Interest income related to Eastern Energy Gas' affiliated notes receivable from East Ohio Gas Company was $18 million for the three-month period ended March 31, 2020.

For the three-month period ended March 31, 2020, Eastern Energy Gas distributed $37 million to DEI.

*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 $21 million and $20 million as of March 31, 2021 and December 31, 2020, respectively.

DEI, BHE, MidAmerican Energy, Northern Natural Gas Company and other related parties provided accounting, human resources, information technology and certain other administrative and technical services to Eastern Energy Gas, which totaled $7 million for the three-month period ended March 31, 2021. Eastern Energy Gas provided certain services to affiliates, including administrative and technical services, which totaled $9 million for the three-month period ended March 31, 2021. Eastern Energy Gas also provided transportation and storage services to affiliates, which totaled $7 million for the three-month period ended March 31, 2021. Other assets included amounts due from an affiliate of $6 million and $7 million as of March 31, 2021 and December 31, 2020, respectively.

Eastern Energy Gas has a $400 million intercompany revolving credit agreement from its parent, BHE GT&S, LLC ("BHE GT&S") expiring in November 2021. 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 London Interbank Offered Rate ("LIBOR") plus a fixed spread. As of March 31, 2021 and December 31, 2020, $— million and $9 million, respectively, was outstanding under the credit agreement.

BHE GT&S has an intercompany revolving credit agreement from Eastern Energy Gas expiring in December 2021. 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 March 31, 2021 and December 31, 2020, $234 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 6. As of March 31, 2021 and December 31, 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 $110 million and $115 million, respectively.

## Item 2. 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 Part I, Item 1 of this Form 10-Q. Eastern Energy Gas' actual results in the future could differ significantly from the historical results.

### Results of Operations for the First Quarter of 2021 and 2020

Overview

Net income for the first three months of 2021 was $89 million, a decrease of $80 million compared to 2020. Net income decreased primarily a result of the GT&S Transaction consisting of an increase in net income attributable to noncontrolling interests due to DEI's 50% noncontrolling interest in Cove Point LNG, LP ("Cove Point") of $69 million and the absence of Questar Pipeline Group operations of $23 million.

Quarter Ended March 31, 2021 Compared to Quarter Ended March 31, 2020

*Operating revenue* decreased $70 million, or 13%, for the first quarter of 2021 compared to 2020, primarily due to the absence of Questar Pipeline Group operations of $64 million and a decrease in services performed for Atlantic Coast Pipeline, LLC of $17 million, which is offset in operations and maintenance expense. The decrease in operating revenue was partially offset by an increase in regulated gas sales primarily due to increased volumes of $17 million.

*Cost of gas* decreased $8 million, or 100%, for the first quarter of 2021 compared to 2020, primarily due to favorable prices of $19 million and the absence of Questar Pipeline Group operations of $2 million, partially offset by an increase in volumes sold of $14 million.

*Operations and maintenance* decreased $44 million, or 26%, for the first quarter of 2021 compared to 2020, primarily due to a decrease in services performed for Atlantic Coast Pipeline, LLC of $17 million and the absence of Questar Pipeline Group operations of $15 million.

*Depreciation and amortization* decreased $13 million, or 14%, for the first quarter of 2021 compared to 2020, primarily due to the absence of Questar Pipeline Group.

*Interest expense* decreased $14 million, or 24%, for the first quarter of 2021 compared to 2020, primarily due to lower interest expense of $7 million from the repayment of $700 million of long-term debt in the fourth quarter of 2020 and the absence of interest expense related to Questar Pipeline Group of $5 million.

*Interest and dividend income* decreased $30 million, or 100%, for the first quarter of 2021 compared to 2020, primarily due to the absence of interest income from the East Ohio Gas Company of $18 million and DEI of $11 million.

*Other, net* decreased $13 million, or 93%, for the first quarter of 2021 compared to 2020, primarily due to a decrease in non-service cost credits related to certain Eastern Energy Gas benefit plans that were retained by DEI as a result of the GT&S Transaction.

*Income tax expense* decreased $25 million for the first quarter of 2021 compared to 2020 and the effective tax rate was 13% for the first quarter of 2021 and 22% for the first quarter of 2020. The effective tax rate decreased primarily due to the change in the noncontrolling interest of Cove Point and lower pre-tax income as a result of the GT&S Transaction.

*Net income attributable to noncontrolling interests* increased $69 million, or 209%, for the first quarter of 2021 compared to 2020 primarily due to DEI's 50% interest in Cove Point effective with the GT&S Transaction.

**Liquidity and Capital Resources**

As of March 31, 2021, Eastern Energy Gas' total net liquidity was $506 million as follows (in millions):

| | |
|---|---|
| Cash and cash equivalents | $ 106 |
| | |
| Intercompany credit agreement[1] | 400 |
| Less: | |
| Notes payable | — |
| Net intercompany credit agreement | 400 |
| | |
| Total net liquidity | $ 506 |
| | |
| Intercompany credit agreement: | |
| Maturity date | 2021 |

(1) Refer to Note 12 of Notes to Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q for further discussion regarding Eastern Energy Gas' intercompany credit agreement.

Operating Activities

Net cash flows from operating activities for the three-month periods ended March 31, 2021 and 2020 were $241 million and $667 million. respectively. The change was primarily due to decreased repayments of affiliated receivables by DEI subsidiaries in 2021 and the absence of the Questar Pipeline Group.

The timing of Eastern Energy Gas' income tax cash flows from period to period can be significantly affected by the estimated federal income tax payment methods elected and assumptions for each payment date.

Investing Activities

Net cash flows from investing activities for the three-month periods ended March 31, 2021 and 2020 were $(56) million and $(342) million. respectively. The change was primarily due to the absence of loans to affiliates of $262 million.

Financing Activities

Net cash flows from financing activities for the three-month period ended March 31, 2021 were $(118) million. Uses of cash totaled $(118) million and consisted mainly of distributions to noncontrolling interests from Cove Point of $109 million.

Net cash flows from financing activities for the three-month period ended March 31, 2020 were $(306) million. Uses of cash totaled $306 million and consisted mainly of distributions of $269 million and repayments of short-term debt of $32 million.

Future Uses of Cash

Eastern Energy Gas 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 credit agreements, capital contributions 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 Eastern Energy Gas and each subsidiary has access to external financing depends on a variety of factors, including regulatory approvals, Eastern Energy Gas' credit ratings, investors' judgment of risk 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; 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.

Eastern Energy Gas' historical and forecasted capital expenditures, each of which exclude amounts for non-cash equity AFUDC and other non-cash items, are as follows (in millions):

| | Three-Month Periods Ended March 31, | | Annual Forecast |
|---|---|---|---|
| | **2020** | **2021** | **2021** |
| Natural gas transmission and storage | $ 23 | $ 8 | $ 30 |
| Other | 53 | 47 | 432 |
| Total | $ 76 | $ 55 | $ 462 |

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 liquefied natural gas terminalling infrastructure needed to serve existing and expected demand.

*Contractual Obligations*

As of March 31, 2021, there have been no material changes outside the normal course of business in contractual obligations from the information provided in Item 7 of Eastern Energy Gas' Annual Report on Form 10-K for the year ended December 31, 2020.

**Regulatory Matters**

Eastern Energy Gas is subject to comprehensive regulation. Refer to Note 4 of Notes to Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q for discussion regarding Eastern Energy Gas' 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 Berkshire Hathaway Energy's Part I, Item 2 of this Form 10-Q for additional information regarding environmental laws and regulations.

**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. Estimates are used for, but not limited to, the accounting for the effects of certain types of regulation, impairment of goodwill and long-lived assets and income taxes. For additional discussion of Eastern Energy Gas' critical accounting estimates, see Item 7 of Eastern Energy Gas' Annual Report on Form 10-K for the year ended December 31, 2020. There have been no significant changes in Eastern Energy Gas' assumptions regarding critical accounting estimates since December 31, 2020.

## Item 3. Quantitative and Qualitative Disclosures About Market Risk

For quantitative and qualitative disclosures about market risk affecting the Registrants, see Item 7A of each Registrant's Annual Report on Form 10-K for the year ended December 31, 2020. Each Registrant's exposure to market risk and its management of such risk has not changed materially since December 31, 2020. Refer to Note 6 of the Notes to Consolidated Financial Statements of PacifiCorp in Part I, Item 1 of this Form 10-Q for disclosure of the respective Registrant's derivative positions as of March 31, 2021.

## Item 4. Controls and Procedures

At the end of the period covered by this Quarterly Report on Form 10-Q, 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 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 Securities Exchange Act of 1934, as amended, 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 March 31, 2021 that has materially affected, or is reasonably likely to materially affect, its internal control over financial reporting.

## PART II

### Item 1. 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. The 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 complaint was amended November 2, 2020, and seeks the following damages: (i) damages for real and personal property and other economic losses in excess of $600 million; (ii) double the amount of property and economic damages based on alleged gross negligence; (iii) treble damages for specific costs associated with loss of timber, trees and shrubbery; (iv) double the damages for the costs of litigation and reforestation; and (v) prejudgment interest. The plaintiffs demand a trial by jury and have reserved their right to amend the complaint to allege claims for punitive damages.

On March 12, 2021, a complaint against PacifiCorp was filed, captioned *Shyla Zeober et al. v. PacifiCorp*, Case No. 21cv09339, Circuit Court, Marion County, Oregon. The 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 for real and personal property and other economic losses in an amount determined by the jury to be fair and reasonable, but not to exceed $150 million; and (ii) noneconomic damages in the amount determined by the jury to be fair and reasonable, but not to exceed $500 million. The plaintiffs demand a trial by jury and have reserved their right to amend the complaint.

On March 15, 2021, a complaint against PacifiCorp was filed, captioned *Shylo Salter et al. v. PacifiCorp*, Case No. 21cv09520, Circuit Court, Marion County, Oregon. The 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 for real and personal property and other economic losses in an amount determined by the jury to be fair and reasonable, but not to exceed $150 million; and (ii) noneconomic damages in the amount determined by the jury to be fair and reasonable, but not to exceed $500 million. The plaintiffs demand a trial by jury and have reserved their right to amend the complaint.

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 9 of the Notes to Consolidated Financial Statements of Berkshire Hathaway Energy in Part I, Item 1 of this Form 10-Q, and PacifiCorp, refer to Note 8 of the Notes to Consolidated Financial Statements of PacifiCorp in Part I, Item 1 of this Form 10-Q.

### Item 1A. Risk Factors

There has been no material change to each Registrant's risk factors from those disclosed in Item 1A of each Registrant's Annual Report on Form 10-K for the year ended December 31, 2020.

### Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

Not applicable.

### Item 3. Defaults Upon Senior Securities

Not applicable.

**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 Wall Street Reform and Consumer Protection Act is included in Exhibit 95 to this Form 10-Q.

**Item 5. Other Information**

Not applicable.

**Item 6. Exhibits**

The following is a list of exhibits filed as part of this Quarterly Report.

| Exhibit No. | Description |
|---|---|
| BERKSHIRE HATHAWAY ENERGY | |
| 4.1 | 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. |
| 15.1 | Awareness Letter of Independent Registered Public Accounting Firm. |
| 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 | |
| 15.2 | Awareness Letter of Independent Registered Public Accounting Firm. |
| 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. |
| BERKSHIRE HATHAWAY ENERGY AND PACIFICORP | |
| 95 | Mine Safety Disclosures Required by the Dodd-Frank Wall Street Reform and Consumer Protection Act. |
| MIDAMERICAN ENERGY | |
| 15.3 | Awareness Letter of Independent Registered Public Accounting Firm. |
| 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 | |
| 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. |
| NEVADA POWER | |
| 15.4 | Awareness Letter of Independent Registered Public Accounting Firm. |
| 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. |

SIERRA PACIFIC

| | |
|---|---|
| 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. |

EASTERN ENERGY GAS

| | |
|---|---|
| 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. |

ALL REGISTRANTS

| | |
|---|---|
| 101 | The following financial information from each respective Registrant's Quarterly Report on Form 10-Q for the quarter ended March 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. |

## SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, each registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

**BERKSHIRE HATHAWAY ENERGY COMPANY**

Date: April 30, 2021

/s/ Calvin D. Haack

Calvin D. Haack
Senior Vice President and Chief Financial Officer
(principal financial and accounting officer)

**PACIFICORP**

Date: April 30, 2021

/s/ Nikki L. Kobliha

Nikki L. Kobliha
Vice President, Chief Financial Officer and Treasurer
(principal financial and accounting officer)

**MIDAMERICAN FUNDING, LLC**
**MIDAMERICAN ENERGY COMPANY**

Date: April 30, 2021

/s/ Thomas B. Specketer

Thomas B. Specketer
Vice President and Controller
of MidAmerican Funding, LLC and
Vice President and Chief Financial Officer
of MidAmerican Energy Company
(principal financial and accounting officer)

**NEVADA POWER COMPANY**

Date: April 30, 2021

/s/ Michael E. Cole

Michael E. Cole
Vice President, Chief Financial Officer and Treasurer
(principal financial and accounting officer)

**SIERRA PACIFIC POWER COMPANY**

Date: April 30, 2021

/s/ Michael E. Cole

Michael E. Cole
Vice President, Chief Financial Officer and Treasurer
(principal financial and accounting officer)

**EASTERN ENERGY GAS HOLDINGS, LLC**

Date: April 30, 2021

/s/ Scott C. Miller

Scott C. Miller
Vice President, Chief Financial Officer and Treasurer
(principal financial and accounting officer)

**EXHIBIT 15.1**

April 30, 2021

To the Board of Directors and Shareholders of
Berkshire Hathaway Energy Company
666 Grand Ave,
Des Moines, Iowa 50306

We are aware that our report dated April 30, 2021, on our review of the interim financial information of Berkshire Hathaway Energy Company appearing in this Quarterly Report on Form 10-Q for the quarter ended March 31, 2021, is incorporated by reference in Registration Statement No. 333-228511 on Form S-8.

/s/ Deloitte & Touche LLP

Des Moines, Iowa

**EXHIBIT 15.2**

April 30, 2021

The Board of Directors and Shareholders of
PacifiCorp
825 N.E. Multnomah Street
Portland, Oregon 97232

We are aware that our report dated April 30, 2021, on our review of the interim financial information of PacifiCorp and subsidiaries appearing in this Quarterly Report on Form 10-Q for the quarter ended March 31, 2021, is incorporated by reference in Registration Statement No. 333-249044 on Form S-3.

/s/ Deloitte & Touche LLP

Portland, Oregon

**EXHIBIT 15.3**

April 30, 2021

To the Board of Directors and Shareholder of
MidAmerican Energy Company
Des Moines, Iowa

We are aware that our report dated April 30, 2021, on our review of the interim financial information of MidAmerican Energy Company appearing in this Quarterly Report on Form 10-Q for the quarter ended March 31, 2021, is incorporated by reference in Registration Statement No. 333-225916 on Form S-3.

/s/ Deloitte & Touche LLP

Des Moines, Iowa

**EXHIBIT 15.4**

April 30, 2021

To the Board of Directors and Shareholder of
Nevada Power Company
Las Vegas, Nevada

We are aware that our report dated April 30, 2021 on our review of the interim financial information of Nevada Power Company and subsidiaries appearing in this Quarterly Report on Form 10-Q for the quarter ended March 31, 2021, is incorporated by reference in Registration Statement No. 333-234207 on Form S-3.

/s/ Deloitte & Touche LLP

Las Vegas, Nevada

**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 Quarterly Report on Form 10-Q 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: April 30, 2021

/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 Quarterly Report on Form 10-Q 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: April 30, 2021

/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 Quarterly Report on Form 10-Q 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: April 30, 2021

/s/ William J. Fehrman
William J. Fehrman
Chairman 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 Quarterly Report on Form 10-Q 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: April 30, 2021

/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 Quarterly Report on Form 10-Q 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: April 30, 2021

/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 Quarterly Report on Form 10-Q 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: April 30, 2021

/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 Quarterly Report on Form 10-Q 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: April 30, 2021

/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 Quarterly Report on Form 10-Q 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: April 30, 2021

/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 Quarterly Report on Form 10-Q of Nevada Power Company (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: April 30, 2021

/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 Quarterly Report on Form 10-Q of Nevada Power Company (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: April 30, 2021

/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 Quarterly Report on Form 10-Q of Sierra Pacific Power Company (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: April 30, 2021

/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 Quarterly Report on Form 10-Q of Sierra Pacific Power Company (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: April 30, 2021

/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 Quarterly Report on Form 10-Q 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: April 30, 2021

/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 Quarterly Report on Form 10-Q 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: April 30, 2021

/s/ Scott C. Miller
Scott C. Miller
Vice President, 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 Quarterly Report on Form 10-Q of the Company for the quarterly period ended March 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 the Company.

Date: April 30, 2021

/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 Quarterly Report on Form 10-Q of the Company for the quarterly period ended March 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 the Company.

Date: April 30, 2021

/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, Chairman 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 Quarterly Report on Form 10-Q of PacifiCorp for the quarterly period ended March 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: April 30, 2021

/s/ William J. Fehrman
William J. Fehrman
Chairman 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 Quarterly Report on Form 10-Q of PacifiCorp for the quarterly period ended March 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: April 30, 2021

/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 Quarterly Report on Form 10-Q of MidAmerican Energy Company for the quarterly period ended March 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: April 30, 2021

/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 Quarterly Report on Form 10-Q of MidAmerican Energy Company for the quarterly period ended March 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: April 30, 2021

/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 Quarterly Report on Form 10-Q of MidAmerican Funding, LLC for the quarterly period ended March 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: April 30, 2021

/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 Quarterly Report on Form 10-Q of MidAmerican Funding, LLC for the quarterly period ended March 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: April 30, 2021

/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 (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 Quarterly Report on Form 10-Q of Nevada Power Company for the quarterly period ended March 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 Nevada Power Company.

Date: April 30, 2021

/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 (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 Quarterly Report on Form 10-Q of Nevada Power Company for the quarterly period ended March 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 Nevada Power Company.

Date: April 30, 2021

/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 (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 Quarterly Report on Form 10-Q of Sierra Pacific Power Company for the quarterly period ended March 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 Sierra Pacific Power Company.

Date: April 30, 2021

/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 (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 Quarterly Report on Form 10-Q of Sierra Pacific Power Company for the quarterly period ended March 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 Sierra Pacific Power Company.

Date: April 30, 2021

/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 Quarterly Report on Form 10-Q of Eastern Energy Gas Holdings, LLC for the quarterly period ended March 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(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: April 30, 2021

/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, Vice President, Chief Financial Officer and Treasurer of Eastern Energy Gas Holdings, LLC, certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Quarterly Report on Form 10-Q of Eastern Energy Gas Holdings, LLC for the quarterly period ended March 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(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: April 30, 2021

/s/ Scott C. Miller
Scott C. Miller
Vice President, 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 three-month period ended March 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 three-month period ended March 31, 2021. There were no mining-related fatalities during the three-month period ended March 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 three-month period ended March 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 | — | — | — | — | $ — | — | — | — |
| Bridger (underground) | 1 | — | — | — | — | 8 | 1 | — | — |
| 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 one contest 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 the MSHA during the reporting period.

# APPENDIX B

# PacifiCorp
# State of California
# ECAC/GHG Application
# Statement of Present and Proposed Rates

| Tariff Schedules | Present Rates | Proposed Rates | |
|---|---|---|---|
| **Schedule D (Standard Residential)** | | | |
| Basic Charge | $7.73 | $7.73 | /month |
| Energy Charge | | | |
| Baseline kWh | 14.315 | 14.071 | ¢/kWh |
| Non-Baseline kWh | 16.277 | 16.033 | ¢/kWh |
| **Schedule DL-6 (Residential CARE)** | | | |
| Basic Charge | $6.18 | $6.18 | /month |
| Energy Charge | | | |
| Baseline kWh | 10.974 | 10.778 | ¢/kWh |
| Non-Baseline kWh | 12.543 | 12.348 | ¢/kWh |
| **Schedule A-25 Secondary** | | | |
| Basic Charge | | | |
| 1 Phase | $14.91 | $14.91 | /month |
| 3 Phase | $20.46 | $20.46 | /month |
| Energy Charge | 16.147 | 16.007 | ¢/kWh |
| **Schedule A-25 Primary** | | | |
| Basic Charge | | | |
| 1 Phase | $14.91 | $14.91 | /month |
| 3 Phase | $20.46 | $20.46 | /month |
| Energy Charge | 15.987 | 15.848 | ¢/kWh |
| **Schedule A-32 Secondary** | | | |
| Basic Charge | | | |
| 1 Phase | $13.70 | $13.70 | /month |
| 3 Phase | $18.80 | $18.80 | /month |
| Distribution Demand Charge | $1.72 | $1.72 | /kW |
| Generation & Transmission Demand Charge | $4.65 | $4.30 | /kW |
| Energy Charge | 11.691 | 11.618 | ¢/kWh |
| Reactive Power | 60.00 | 60.00 | ¢/kVar |
| **Schedule A-32 Primary** | | | |
| Basic Charge | | | |
| 1 Phase | $13.70 | $13.70 | /month |
| 3 Phase | $18.80 | $18.80 | /month |
| Distribution Demand Charge | $1.20 | $1.20 | /kW |
| Generation & Transmission Demand Charge | $4.65 | $4.30 | /kW |
| Energy Charge | 11.575 | 11.503 | ¢/kWh |
| Reactive Power | 60.00 | 60.00 | ¢/kVar |
| High Voltage Charge | $60.00 | $60.00 | /month |

Reflects present rates in effect at the time of the intial filing in this docket.

# PacifiCorp
# State of California
# ECAC/GHG Application
# Statement of Present and Proposed Rates

| Tariff Schedules | Present Rates | Proposed Rates | |
|---|---|---|---|
| **Schedule A-36 Secondary** | | | |
| Basic Charge | $244.32 | $244.32 | /month |
| Distribution Demand Charge | $3.16 | $3.16 | /kW |
| Generation & Transmission Demand Charge | $8.90 | $8.16 | /kW |
| Energy Charge | 9.183 | 9.015 | ¢/kWh |
| Reactive Power | 60.00 | 60.00 | ¢/kVar |
| **Schedule A-36 Primary** | | | |
| Basic Charge | $244.32 | $244.32 | /month |
| Distribution Demand Charge | $2.21 | $2.21 | /kW |
| Generation & Transmission Demand Charge | $8.90 | $8.16 | /kW |
| Energy Charge | 9.092 | 8.926 | ¢/kWh |
| Reactive Power | 60.00 | 60.00 | ¢/kVar |
| High Voltage Charge | $60.00 | $60.00 | /month |
| **Schedule AT-48 Secondary** | | | |
| Basic Charge | $442.05 | $442.05 | /month |
| Distribution Demand Charge | $1.89 | $1.89 | /kW |
| Generation & Transmission Demand Charge (Summer) | $7.37 | $6.68 | /kW |
| Generation & Transmission Demand Charge (Winter) | $8.00 | $7.31 | /kW |
| Energy Charge | 8.021 | 7.767 | ¢/kWh |
| Reactive Power | 60.00 | 60.00 | ¢/kVar |
| **Schedule AT-48 Primary/Transmission** | | | |
| Basic Charge | $442.05 | $442.05 | /month |
| Distribution Demand Charge | $1.32 | $1.32 | /kW |
| Generation & Transmission Demand Charge (Summer) | $7.37 | $6.68 | /kW |
| Generation & Transmission Demand Charge (Winter) | $8.00 | $7.31 | /kW |
| Energy Charge | 7.942 | 7.691 | ¢/kWh |
| Reactive Power | 60.00 | 60.00 | ¢/kVar |
| High Voltage Charge | $60.00 | $60.00 | /month |
| **Schedule PA-20** | | | |
| Basic Charge - Annually (billed in November) | | | |
| 1 Phase Any Size, 3 Phase <= 50kW | $77.82 | $77.82 | |
| 3 Phase Load Size > 50 kW | $160.76 | $160.76 | |
| Distribution Demand Charge - Annually (billed in November) | $17.15 | $17.15 | /kW |
| Generation & Transmission Demand Charge | $5.90 | $5.49 | /kW |
| Energy Charge | 10.344 | 10.241 | ¢/kWh |
| Reactive Power | 60.00 | 60.00 | ¢/kVar |

# PacifiCorp
# State of California
# ECAC/GHG Application
# Statement of Present and Proposed Rates

| Tariff Schedules | | | | Present Rates | Proposed Rates | |
|---|---|---|---|---|---|---|
| **Schedule OL-15** | | | | | | |
| | *lumen* | | *kWh* | | | |
| Mercury Vapor | 7,000 | | 76 | $18.45 | $18.54 | /Lamp |
| Mercury Vapor | 21,000 | | 172 | $38.85 | $39.07 | /Lamp |
| Mercury Vapor | 55,000 | | 412 | $88.15 | $88.66 | /Lamp |
| High Pressure Sodium | 5,800 | | 31 | $14.88 | $14.92 | /Lamp |
| High Pressure Sodium | 22,000 | | 85 | $27.39 | $27.50 | /Lamp |
| High Pressure Sodium | 50,000 | | 176 | $49.15 | $49.37 | /Lamp |
| **Schedule OL-42** | | | | | | |
| Basic Charge | | | | | | |
| Single Phase | | | | $9.58 | $9.58 | /month |
| Three Phase | | | | $13.12 | $13.12 | /month |
| All kWh | | | | 18.119 | 18.070 | ¢/kWh |
| **Schedule LS-51** | | | | | | |
| | *lumen* | *Watts* | *kWh* | | | |
| **HPSV - Functional** | | | | | | |
| High Pressure Sodium | 5,800 | 70 | 31 | $10.92 | $11.00 | /Lamp |
| High Pressure Sodium | 9,500 | 100 | 44 | $13.11 | $13.23 | /Lamp |
| High Pressure Sodium | 16,000 | 150 | 64 | $18.01 | $18.19 | /Lamp |
| High Pressure Sodium | 22,000 | 200 | 85 | $23.05 | $23.28 | /Lamp |
| High Pressure Sodium | 27,500 | 250 | 115 | $30.33 | $30.65 | /Lamp |
| High Pressure Sodium | 50,000 | 400 | 176 | $45.39 | $45.88 | /Lamp |
| **Decorative Series 1** | | | | | | |
| High Pressure Sodium | 9,500 | 100 | 44 | $34.91 | $35.03 | /Lamp |
| High Pressure Sodium | 16,000 | 150 | 64 | $37.38 | $37.56 | /Lamp |
| **Decorative Series 2** | | | | | | |
| High Pressure Sodium | 9,500 | 100 | 44 | $28.80 | $28.92 | /Lamp |
| High Pressure Sodium | 16,000 | 150 | 64 | $31.23 | $31.41 | /Lamp |
| **LED - Functional** | | | | | | |
| Light Emitting Diode | 4,000 | 50 | 17 | $10.27 | $10.31 | /Lamp |
| Light Emitting Diode | 6,200 | 75 | 25 | $14.08 | $14.15 | /Lamp |
| Light Emitting Diode | 13,000 | 135 | 47 | $26.61 | $26.75 | /Lamp |
| Light Emitting Diode | 16,800 | 185 | 64 | $39.22 | $39.40 | /Lamp |

Reflects present rates in effect at the time of the intial filing in this docket.

# PacifiCorp
# State of California
# ECAC/GHG Application
# Statement of Present and Proposed Rates

| Tariff Schedules | | | | Present Rates | Proposed Rates | |
|---|---|---|---|---|---|---|
| **Schedule LS-53** | | | | | | |
| | *lumen* | *Watts* | *kWh* | | | |
| High Pressure Sodium | 5,800 | 70 | 31 | $4.75 | $4.68 | /Lamp |
| High Pressure Sodium | 9,500 | 100 | 44 | $6.77 | $6.67 | /Lamp |
| High Pressure Sodium | 16,000 | 150 | 64 | $9.81 | $9.66 | /Lamp |
| High Pressure Sodium | 22,000 | 200 | 85 | $13.05 | $12.86 | /Lamp |
| High Pressure Sodium | 27,500 | 250 | 115 | $17.64 | $17.38 | /Lamp |
| High Pressure Sodium | 50,000 | 400 | 176 | $27.02 | $26.63 | /Lamp |
| Non-Listed Luminaire | | | | 15.351 | 15.125 | ¢/kWh |
| **Schedule LS-58** | | | | | | |
| **Class A** | *lumen* | | *kWh* | | | |
| Incandescent | 2,500 | | 73 | $13.36 | $13.27 | /Lamp |
| Mercury Vapor | 7,000 | | 76 | $13.92 | $13.82 | /Lamp |
| Mercury Vapor | 21,000 | | 172 | $31.50 | $31.29 | /Lamp |

# APPENDIX C

**Appendix C**
**PacifiCorp**
**Summary of Earnings**
**Twelve Months Ended December 31, 2020**

| Line | Item | California |
|---|---|---|
| 1 | Operating Revenue | $99,502,572 |
| 2 | Operating Expenses | $76,461,214 |
| 3 | Operating Revenue for Return | $23,041,358 |
| 4 | Total Rate Base | $284,849,438 |
| 5 | Return on Rate Base | 8.09% |

Application No. 21-08-_____
Exhibit No. PAC/100 - 106
Witness: Douglas R. Staples

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP 2022 ECAC

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Direct Testimony of Douglas R. Staples

August 2, 2021

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**Attached Exhibits**

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## I. Witness Qualifications

**Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or Company).**

A. My name is Douglas R. Staples and my business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. I am currently employed as a Net Power Cost Advisor in the Net Power Costs Group.

**Q. Briefly describe your education and business experience.**

A. I received a Bachelor of Science degree with a focus on finance from the University of South Florida. I originally began working for PacifiCorp in early 2015, and during my tenure at PacifiCorp, I have worked as a senior risk management analyst. After a brief departure from the Company, in 2019 I returned to work at PacifiCorp as a Net Power Cost Advisor. In my current role, I am responsible for leading and overseeing all modeling efforts associated with the Company's net power costs (NPC) for regulatory purposes and various other regulatory filings using Generation and Regulation Initiative Decision Tools (GRID) and the Aurora production cost model. Before my time with PacifiCorp, I spent seven years working as a senior risk analyst and a supervisor of the risk management group at NextEra Energy Power Marketing where I designed reports, provided validation and troubleshooting of risk metrics, and oversaw the validation of valuation assumptions used in mark to market accounting for financial statements. Prior to that, I worked as a principal business analyst for San Diego Gas & Electric where I was a part of the acting arm of the risk management committee, providing oversight to both San Diego Gas & Electric Company and Southern California Gas Company.

**Q. Have you testified in previous regulatory proceedings?**

A. Yes. I have previously provided testimony to the public utility commissions in Oregon and Washington.

## II. Summary of Testimony

**Q. Please summarize your direct testimony.**

A. I present the Company's proposed Energy Cost Adjustment Clause (ECAC) Balancing Rate and Offset Rate calculations for calendar year 2022 (2022 ECAC). In addition, my testimony:

- Includes a discussion on the Company's transition to the Aurora model for the purpose of forecasting net power costs (NPC) in this filing;
- Presents the updated 2020 adjusted actual and 2021 adjusted actual/projected net power costs, which are used to develop the 2022 Balancing Rate;
- Includes a discussion about the Company's participation in the energy imbalance market (EIM) with the California Independent System Operator (CAISO) and the benefits from EIM that are passed through to customers;
- Presents the 2022 projected NPC, which are used to develop the 2022 Offset Rate;
- Describes the determination of NPC using the Company's production cost model, Aurora; and
- Describes the treatment of fuel stock carrying charges, costs for implementation and reporting verification under the California Air Resources Board (ARB) Mandatory Reporting Rule and Cap and Trade Program (ARB administrative costs), net metering surplus costs, purchases of renewable

energy certificates (RECs) for renewables portfolio standard (RPS) compliance, renewable energy production tax credits (PTCs), and start-up fuel costs.

**Q. Please provide an overview of the ECAC filing.**

A. In this 2022 ECAC filing, the Company is requesting recovery of approximately $3.1 million through the Balancing Rate to true-up collection of actual NPC during 2020 and 2021. The change in the Balancing Rate results in a $2.4 million decrease compared to rates currently in effect that were approved in Decision (D.) 20-12-004, the Company's 2020 ECAC and GHG Application, Application (A.) 19-08-002. The Company is also proposing to adjust the Offset Rate for 2022 resulting in a rate decrease of approximately $3.0 million as compared to rates currently in effect that were approved in D.20-12-004. Compared to total-Company NPC proposed in the 2021 ECAC,[1] projected NPC in the 2022 ECAC are higher by 4.1 percent. As shown in Exhibit PAC/101, Line 14, the proposed 2022 Offset Rate is $25.15 per megawatt-hour (MWh), which is an increase of 5.3 percent from the rate of $23.88 per MWh, which the Company proposed in its 2021 ECAC and GHG Application, A.20-08-002 (2021 Application). With the change in the Offset Rate greater than the five percent threshold, the Company proposes to change the rate for 2022 and increase the 2022 Balancing Rate.

In addition to NPC, the Balancing Rate and Offset Rates include changes to ARB administrative costs, net metering surplus compensation, fuel stock carrying charges, REC purchases for RPS compliance, PTCs, and start-up fuel costs.

[1] A Commission decision regarding the Company's 2021 ECAC in A.21-08-002 is still pending.

Renewable energy PTCs and start-up fuel costs have been included in accordance with the Commission's decision in the Company's 2019 Rate Case filing, A.18-04-002 (2019 Rate Case), D.20-02-025.

Summary calculations of the Balancing Rate and Offset Rate are provided in Exhibit PAC/101. If approved, the proposed rates would take effect January 1, 2022. Ms. Judith M. Ridenour provides testimony describing the impact on customers' rates (Exhibit PAC/600).

**Q. Please explain the status of the Company's 2021 Application.**

A. The 2021 Application filed by the Company is still pending approval from the Commission. The GHG-related costs and allowance proceeds portion of the 2021 Application was approved by the Commission in D.21-03-007. With respect to the ECAC portion of the 2021 Application, the case has been fully heard and briefed and awaits a final decision. In preparing the 2022 ECAC Offset and Balancing Rates, PacifiCorp has assumed that the Offset and Balancing Rates proposed in the 2021 Application will be approved by the Commission.[2] To the extent that those rates are modified in any way by a final decision in the case, PacifiCorp will true up its 2022 Application to reflect such changes. This could be done by supplemental testimony, or by an amendment to the 2022 ECAC application, and PacifiCorp will consider the appropriate procedural means for an adjustment to reflect a final decision in the 2021 ECAC after it has been issued.

**Q. Please describe Exhibit PAC/101.**

[2] However, the present rates and rate impact calculation presented in Exhibit PAC/600 do not reflect the pending rates proposed in A.21-08-002, but rather rates that are currently in place.

A. Exhibit PAC/101 shows the calculation of the proposed Offset and Balancing Rates for the 2022 rate effective period. Lines 1 through 14 are used to develop the Offset Rate. Lines 15 through 61 are used to develop the Balancing Rate.

## III. Transition to Aurora Model

**Q. Why is PacifiCorp estimating NPC with the Aurora model in this filing?**

A. PacifiCorp's former model, GRID, has been used to forecast costs since it was deployed by the Company in 2008. Moving to the Aurora model, which is produced by Energy Exemplar, provides some additional functionality, increases usability, and compatibility with the Company's information technology and cyber security requirements.

**Q. How does the Aurora model work?**

A. Aurora is designed to model the competitive wholesale electricity market and produce hourly market prices to meet load requirements at various locations (referred to as "zones"). This is accomplished by simulating the dispatch of available resources, both supply-side and demand-side, within physical and economic constraints of the resources, as well as profiles of the load requirements. These simulations determine the resources at the margin in each hour to serve the next incremental amount of load requirements of the zones and the costs of the resources at the margin, which set the market prices of the zones.

**Q. How does Aurora compare to GRID?**

A. The model logic is generally the same between Aurora and GRID; both models minimize costs to serve obligations under various constraints. While the categories of inputs are generally the same between the two models, Aurora has more parameters to model resources and more flexibility to model different types of resources.

**Q. Are there any other changes being made to the filing that can be attributed to the transition from GRID to Aurora?**

A. Yes. In previous ECAC filings, because of the limitations in the GRID model, the Company needed to engage in an iterative process to ensure the optimal marginal costs used for the coal plant dispatch were reflective of the Company's coal supply agreements (CSAs). In approving the Company's Offset and Balancing Rates in the 2020 Application (A.19-08-002) in D.20-12-004, the Commission found that "[s]ince PacifiCorp must pay the full price of fuel for any purchases below minimum take requirements, we agree that ratepayers are likely to benefit from ensuring all minimum take requirements are met …"[3] While finding the Company's iterative process appropriate, the Commission required more transparency and directed the Company to produce the following information in its ECAC applications going forward:

1. information on the marginal fuel cost assumed for each coal plant, the specific coal plants where adjustments were made to align forecasted generation with minimum take provisions, and the magnitude of adjustments made;
2. a GRID model run that depicts the NPC when adjustments are made to the Dispatch Tier meet minimum take provisions;
3. a GRID model run that depicts the NPC when the Dispatch Tier is based purely on marginal costs; and
4. a GRID model run that depicts the NPC when average fuel costs are utilized to forecast unit dispatch. [4]

The Aurora model used by the Company in this proceeding has greater flexibility around the modeling of fuel consumption. In addition, the Aurora model

[3] D.20-12-004 at 16.
[4] *Id.,* at 16-17. Pursuant to D.20-12-004, PacifiCorp provided this information in the 2021 ECAC as supplemental testimony on February 5, 2021.

neither has a "dispatch tier," nor a "costing tier" like GRID; Aurora utilizes the same data variables for dispatch and cost determination. Finally, the model can recognize volumetric contract provisions as a binding constraint in the optimization.

As a result, the base NPC in this case is being forecasted using tiered costs and volumes per each plant's CSAs and, thus, the iterative process previously used in GRID is no longer needed. Because the iterative process is no longer needed using Aurora, there are no adjustments to identify or quantify. In addition, as the tiers are no longer blended due to Aurora's more robust modeling capabilities, the average cost run is no longer required either. With the modeling enhancements captured by the transition to Aurora, the previously ordered studies noted above are no longer relevant or needed.

## IV. Adjusted Actual Net Power Costs

**Q. Please explain adjusted actual NPC.**

A. NPC are defined as the sum of the Company's fuel expenses, wholesale purchase power expenses, and wheeling expenses, less wholesale sales revenue. Adjusted actual NPC are the sum of total-Company amounts recorded in Federal Energy Regulatory Commission Accounts 501, 503 and 547 (Steam Production Fuel Expense) for the Company's coal, geothermal, and natural gas resources; 555 (Purchased Power); and 565 (Wheeling); less Account 447 (Sales for Resale). These amounts are adjusted to: (1) align booked NPC in those accounts with NPC used in the rate setting process, ensuring only comparable costs are used in the deferral calculation; and (2) remove prior-period accounting entries, if any, recorded during the deferral period that are not applicable to the current period.

**Q. Why are the 2020 adjusted actual NPC different from what the Company included in its 2021 ECAC filing?**

A. At the time of the 2021 ECAC filing, actual NPC were only available for January through May 2020. As a result, the data used to calculate the 2021 Balancing Rate included five months of adjusted actual NPC (January through May 2020) and seven months of projected NPC (June through December 2020). In the current filing, the Company updated its 2020 data to incorporate the actual NPC for the entire 12--month period. The 2020 adjusted actual NPC are shown in Exhibit PAC/102.

**Q. Which months in 2021 reflect adjusted actual NPC in the current filing?**

A. January through May 2021 reflect adjusted actual NPC while June through December 2021 are a projection of the Company's NPC for the balance of the year. Consistent with the design of the ECAC, these are combined to reflect the overall expected NPC for 2021. The 2021 adjusted actual/projected NPC are shown in Exhibit PAC/103.

**Q. How will the projected NPC be reconciled to actual NPC?**

A. In its annual ECAC filings, the Company compares adjusted actual NPC to amounts previously projected. The difference between adjusted actual NPC and the projected amount on a California-allocated basis is tracked in the ECAC balancing account where it accrues interest based on the nonfinancial commercial paper rate. Amounts included in the ECAC balancing account are recovered from or refunded to customers through the Balancing Rate.

## V. 2022 Balancing Rate

**Q. Please describe the components included in the 2022 Balancing Rate.**

A. The Balancing Rate is the rate that returns to or recovers from customers the actual deferred NPC accumulated in the ECAC balancing account. Table 1 shows the individual components making up the Balancing Rate for 2022.

**Table 1**

| | ECAC Balancing Rate | | | |
|---|---|---|---|---|
| | **Balancing Account** | | | |
| **1** | Balancing Account Balance 12/31/2020 | | $ | 2,708,020 |
| **2** | 2020 NPC Variance | | | 114,316 |
| **3** | 2021 NPC Variance | | | (651,117) |
| **4** | Fuel Stock Carrying Charge, ARB Admin Costs, Net Metering Costs, REC Purchases, PTCs, and Start-Up Fuel Costs | | | 932,995 |
| **5** | Interest | | | 2,680 |
| **6** | **Total Balancing Account** | Sum of Lines 1 - 5 | **$** | **3,106,894** |
| **7** | California Projected Sales (MWh) | | | 747,460 |
| **8** | Balancing Rate $/MWh | Line 6 / Line 7 | $ | 4.16 |
| **9** | Billing Factor (Franchise Fees & Uncollectible Accounts) | | | 102.1% |
| **10** | **Balancing Rate with Billing Factor $/MWh** | Line 8 x Line 9 | **$** | **4.25** |

As shown in Table 1, the 2022 Balancing Rate is calculated by:

(1) Determining the total amount in the ECAC balancing account (Table 1, Line 6) by accumulating the sum of:

- the unrecovered amount from previous ECAC filings remaining in the ECAC balancing account as of December 31, 2020;
- the variance between 2020 adjusted actual NPC and the amount projected in the 2021 ECAC filing;

- the variance between 2021 adjusted actual/projected NPC and the NPC projected in the 2021 ECAC filing;
- the fuel stock carrying charge, the ARB administrative costs, net metering surplus compensation, REC purchases for RPS compliance, PTCs, and Start-Up Fuel costs; and,
- interest accumulated on the balance of the ECAC balancing account.

(2) Dividing the total balance of the ECAC balancing account (Table 1, Line 6) by the California projected retail sales (Table 1, Line 7) included in the Company's 2019 Rate Case.

(3) Grossing-up the result for the ECAC Billing Factor (Table 1, Line 9) to account for franchise fees and uncollectible accounts expense, as included in the Company's 2019 Rate Case.

**Q. What is the Company's proposed Balancing Rate?**

A. As shown in Table 1 and in Exhibit PAC/101, Line 60, the proposed Balancing Rate is $4.25 per MWh.

**Q. What is the total dollar amount to be collected through the Balancing Rate in 2022?**

A. Accumulating the 2020 residual balance and the incremental deferrals for 2020 and 2021, plus interest, results in a total of approximately $3.1 million to be collected from customers through the Balancing Rate. The total includes amounts for the fuel stock carrying charges, net metering surplus compensation, ARB administrative costs, REC purchases for RPS compliance, PTCs, and start-up fuel costs.

**Q. Please explain the difference between the amount of NPC that was anticipated to**

**be deferred during 2020 and the actual NPC deferred during 2020.**

A. In its 2021 ECAC filing, the 2020 deferral was calculated using actual information from January through May 2020 and a projection of NPC and related collections from customers for the remainder of the year. The Company anticipated that during 2020 it would accumulate an over-recovery of approximately $1.1 million from customers. The actual amount deferred for 2020 was an over-recovery of $1.0 million, or a difference of $114,000 from projected levels, as shown on Line 49 of Exhibit PAC/101.

The $1.0 million over-recovery consists of two components: (1) actual NPC for 2020 was approximately $251,000 higher than projected on a California-allocated basis; and (2) collections from customers through the Offset Rate in effect during 2020 were approximately $1.2 million higher than projected, causing the deferred balance to increase. Adjusted Actual NPC were higher than anticipated NPC, in part due to lower wholesale sales revenue, but partially offset by lower coal costs, natural gas costs, and purchase power expense.

**Q. Please describe the changes that caused an increase in NPC during 2020.**

A. Overall, the variance between total Company Actual NPC and the Offset Rate for 2020 was $9.8 million or 0.7 percent. While wholesale sales revenue was $151 million lower than projected in the 2020 ECAC, that was mostly offset by lower coal costs of $76 million, lower gas costs of $38 million, and purchased power expense $30 million.

**Q. Please describe why collections from customers through the Offset Rate were higher than expected during 2020.**

A. Collections through the Offset Rate are based on customer usage. The Offset Rate for 2020 was determined using the California retail sales included in the Company's 2019 Rate Case. In 2020, customer usage was approximately 11,000 MWh higher than the MWh assumption in the 2019 Rate Case.

**Q. Please explain the amount the Company expects to defer to the ECAC balancing account during 2021.**

A. Based on actual NPC data for five months (January through May 2021) and projected NPC for seven months (June through December 2021), the Company anticipates it will defer an approximate reduction of $651,000 to the ECAC balancing account during 2021. The residual balance of approximately $2.7 million in the balancing account at the end of 2020 is added to the expected 2021 deferral and the net result is approximately $2.1 million to be collected from customers as shown on line 49 of Exhibit PAC/101.

## VI. <u>2022 Offset Rate</u>

**Q. Please explain the 2022 Offset Rate.**

A. The Offset Rate is the amount of California-allocated 2022 NPC, fuel stock carrying charges, ARB administrative costs, net metering surplus compensation, REC purchases for RPS compliance, PTCs, and start-up fuel costs that will be recovered from customers for the forecast test year (2022). According to the Commission-approved terms of the ECAC mechanism, if the change in the Offset rate exceeds a threshold of five percent, the rate is updated for the upcoming rate effective period. Compared to NPC in the 2021 ECAC, forecast NPC in the 2022 ECAC are higher by 4.1 percent. Additionally, the inclusion of PTCs in the 2022 ECAC decreases net power cost even further and thereby decreases the Offset Rate. The proposed Offset Rate is $25.15 per MWh, which is an increase of 5.3 percent from the rate of $23.88 per MWh, as proposed in the Company's 2021 Application. With the change in the Offset Rate greater than the five percent threshold, the Company proposes to change the Offset Rate for 2022.

**Q. Please explain the calculation of the Offset Rate for 2022.**

A. The Offset Rate is calculated by:

(1) summing the projected California-allocated 2022 NPC, fuel stock carrying charges, ARB administrative costs, net metering surplus compensation, REC purchases for RPS compliance, PTCs, and start-up fuel costs;

(2) dividing by the projected California retail sales; and

(3) grossing up the amount by the ECAC Billing Factor to account for franchise fees and uncollectible accounts expense.

As shown in Exhibit PAC/101, Line 14, the calculated 2022 Offset Rate is $25.15 per MWh. The rate is composed of approximately $22.3 million in California-allocated NPC, $0.01 million of fuel stock carrying charges, $0.05 million in ARB administrative costs, $0.2 million of REC purchases for RPS compliance, a credit of $4.2 million for PTCs, and $0.06 million of start-up fuel costs. Net metering surplus compensation is currently not a material charge, so the Company has not included a projection for these costs in 2022. In the future, these costs may increase and the Company may include a forecast as part of future Offset Rate calculations. All components of the 2022 Offset Rate are calculated based on the 2019 Rate Case.

## VII. 2022 Projected Net Power Costs

**Q. How does the Company calculate its projected NPC?**

A. NPC are calculated for a future period based on projected data using Aurora, which is a production cost model that simulates the operation of the Company's power system on an hourly basis.

**Q. Is the Company's general approach to the calculation of NPC using the Aurora model the same in this case as in previous ECAC filings?**

A. The general approach remains the same. However, as noted previously in my testimony, the model has been modified in this case, with Aurora replacing the previously used GRID model.

**Q. What Aurora inputs were updated for this filing?**

A. Aurora model inputs were updated to include:

- The Company's March 31, 2021 official forward price curve for electricity and natural gas prices;
- New wholesale electricity sales and purchase transactions, both physical and financial;
- New natural gas purchase and sales transactions, both physical and financial;
- New wheeling contracts and updates to transmission paths and capacity, including on Company-owned transmission;
- Updates to existing contracts for wholesale sales and purchases of electricity and natural gas and for wheeling;
- New and updated coal supply and transportation contracts and costs at the Company's captive mines;

- Updates to the capabilities of the Company's owned generation resources and the cost to integrate wind generation and load on the Company's system; and
- Updates to forecast loads.

**Q. What reports does the Aurora model produce?**

A. The major output from the Aurora model is the NPC report. The 2022 report is attached as Exhibit PAC/104.

**Q. Does the Aurora model appropriately reflect the Company's projected NPC over the 2022 test period?**

A. Yes. The Aurora model is a reasonable simulation of the operation of the Company's system load and resource portfolio, consistent with the Company's system operation constraints and requirements. Any variances from projected NPC are handled through the ECAC balancing account, where projected NPC are trued up to adjusted actual NPC on a monthly basis.

**Q. What are the projected NPC for 2022?**

A. The Company's projected NPC for calendar year 2022 are $1.461 billion, or approximately $22.3 million on a California-allocated basis. The Company's 2022 NPC study is provided as Exhibit PAC/104, and the allocation of the Company's NPC to California is provided as Exhibit PAC/105.

**Q. Does the 2022 NPC include any new purchase contracts that exceed more than one percent of the load associated with purchased power?**

A. Yes. The Company has included one new purchase contract that was not included in the 2021 ECAC. This contract accounts for $6.3 million of purchased power expense in 2021 on a total-Company basis which accounts for more than one percent of total purchased power load and has been provided as a separate workpaper.[5]

## VIII. Fuel Stock Carrying Charge

**Q. Does the 2022 Offset Rate include the forecast carrying charges on fuel stock balances?**

A. Yes. The 2022 Offset Rate includes a forecast carrying charge of $14,874.

**Q. Does the 2022 Balancing Rate also include a true up of actual fuel stock carrying charges?**

A. Yes. The 2022 Balancing Rate includes a credit of $10,266 (including interest) to true up fuel stock carrying charges to actual costs in 2020 and 2021. Actual carrying charges for 2020 and 2021 were higher than projected due to differences in fuel stock balances and interest rates used to determine the carrying charges previously.

## IX. ARB Administrative Costs

**Q. Does the 2022 Offset Rate include ARB administrative costs?**

A. Yes. The 2022 Offset Rate includes $46,189 of ARB administrative costs.

**Q. Does the 2022 Balancing Rate include ARB administrative costs that were booked to the memorandum account authorized in the Company's 2012 ECAC?**

A. Yes. The proposed Balancing Rate includes a surcharge of $18,230 (including interest) to account for the difference between actual and forecast ARB administrative costs. Confidential Exhibit PAC/106 provides a summary of the costs booked in 2020 and 2021, as well as a projection of 2022 costs.

[5] The ECAC settlement approved in PacifiCorp's 2005 general rate case (A.05-11-022) stipulates that the Company will provide copies of all new purchase contracts that account for more than one percent of total purchased power load.

## X. Net Metering Surplus Costs

**Q. Does the 2022 Offset Rate include the forecast net metering surplus costs?**

A. No. Net metering surplus compensation is currently an immaterial charge, so the Company has not included a projection for this cost in 2022.

**Q. Does the 2022 Balancing Rate also include a true up of actual net metering surplus costs?**

A. Yes. The 2022 Balancing Rate includes $8,328 (including interest) to true up net metering surplus costs to actual costs in 2020 and 2021.

## XI. Renewable Energy Credits

**Q. Does the Company's 2022 ECAC filing include any revenue from the sale of RECs?**

A. No. The Company has not sold any of its California-allocated RECs; rather, these RECs have been retained for compliance with California's RPS.

**Q. Does the 2022 Offset Rate include the forecast of any costs from the purchase of RECs?**

A. Yes. The 2022 Offset Rate includes a forecast of $192,219.

**Q. Does the 2022 Balancing Rate include a true up of actual REC purchases for RPS Compliance?**

A. Yes. The 2022 Balancing Rate includes $237,353 (including interest) to true up REC purchases to actual purchases for RPS Compliance in 2020 and 2021.

## XII. Production Tax Credits

**Q. Does the 2022 Offset Rate include the forecast of renewable energy PTCs?**

A. Yes. The 2022 Offset Rate includes a credit of $4,151,872 based on the forecasted wind generation attributed to PTCs.

**Q. Does the 2022 Balancing Rate include a true up of actual PTCs?**

A. Yes. The 2022 Offset Rate includes a surcharge of $674,753 (including interest) to true up forecasted PTCs to actual PTCs in 2020 and 2021.

## XIII. Start-up Fuel Costs

**Q. Does the 2022 Offset Rate include the forecast of any start-up fuel costs?**

A. Yes. The 2022 Offset Rate includes a forecast of $58,712 for start-up fuel costs.

**Q. Does the 2022 Balancing Rate include a true up of actual start-up fuel costs?**

A. Yes. The 2022 Offset Rate includes a surcharge of $5,978 (including interest) to true up start-up fuel costs to actual costs in 2020 and 2021.

## XIV. Energy Imbalance Market

**Q. Are the actual benefits from participating in the EIM with CAISO included in the ECAC deferral?**

A. Yes. Participation in the EIM provides benefits to customers in the form of reduced Actual NPC. The EIM benefits are embedded in Actual NPC through lower fuel and purchased power costs. The Company is able to calculate the margin realized on its EIM imports and exports, or the total inter-regional benefit. The Company's EIM inter-regional benefit for the deferral period was approximately $46.7 million.

**Q. How does the Company calculate its actual EIM benefits?**

A. Using actual information from the EIM, including five- and 15-minute pricing, the Company identifies the incremental resource that could have facilitated the transfer to an adjacent EIM area or the CAISO in each five-minute interval. The benefit is then calculated as the difference between the revenue received less the expense of generation assumed to supply the transfer. In the event of an import, the benefit is equal to the cost of the import minus the avoided expense of the generation that would have otherwise been dispatched.

**Q. Does this conclude your direct testimony?**

A. Yes.

Application No. 21-08-_____
Exhibit No. PAC/101
Witness: Douglas R. Staples

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP 2022 ECAC

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California ECAC Offset/Balancing Rate Calculation

August 2, 2021

**Exhibit PAC/101**
**California ECAC Offset / Balancing Rate Calculation**
**August 2, 2021**

| Line | | 2020 Projected | 2021 Projected | 2022 Projected |
|---|---|---|---|---|
| | **ECAC Implementation** | | | |
| | **ECAC Offset Rate** | | | |
| 1 | Total Company Projected ECAC NPC | $ 1,503,542,250 | $ 1,403,343,385 | $ 1,460,956,065 |
| 2 | California Allocated Projected NPC | 22,829,800 | 21,394,283 | 22,259,157 |
| 3 | California Allocated Carrying Charge of Fuel Stock | 31,340 | 13,255 | 14,874 |
| 4 | California ARB Administrative Costs | 47,845 | 82,419 | 46,189 |
| 5 | California Net Metering Surplus Costs | - | - | - |
| 6 | California Allocated Renewable Energy Credits Purchases | 112,189 | 75,487 | 192,219 |
| 7 | California Allocated Production Tax Credits | (1,691,766) | (4,138,141) | (4,151,872) |
| 8 | California Allocated Start-Up Fuel Costs | 65,673 | 61,701 | 58,712 |
| 9 | California Projected Sales in MWh | 747,460 | 747,460 | 747,460 |
| 10 | Projected ECAC Offset Rate $/MWh | $ 28.62 | $ 23.40 | $ 24.64 |
| 11 | Offset Rate Percentage Change | -3.5% | -18.2% | 5.3% |
| 12 | **ECAC Offset Rate $/MWh** | $ 28.62 | $ 23.40 | $ 24.64 |
| 13 | **Billing Factor (Franchise Fees & Uncollectible Accounts)** | 102.1% | 102.1% | 102.1% |
| 14 | **ECAC Offset Rate with Billing Factor $/MWh** | $ 29.21 | $ 23.88 | $ 25.15 |

| Line | | 2020 Actual | 2021 Actual/Projected |
|---|---|---|---|
| | **ECAC Balancing Rate** | | |
| 15 | Total Company Projected NPC | $ 1,503,542,250 | $ 1,403,343,385 |
| 16 | Total Company Adjusted Actual NPC | 1,513,316,797 | 1,503,529,458 |
| 17 | Variance (Line 16 - Line 15) | $ 9,774,547 | $ 100,186,073 |
| | **Total Company Component Variance** | | |
| | **Wholesale Sales Revenue** | | |
| 18 | Firm | $ (151,196,311) | $ 169,982,775 |
| 19 | Non-Firm | - | 0 |
| | **Purchase Power Expense** | | |
| 20 | Seasonal | - | - |
| 21 | Existing Demand | (9,029,875) | 2,232,970 |
| 22 | Existing Energy | (12,700,562) | 7,010,970 |
| 23 | QF | 9,481,084 | 236,078 |
| 24 | Firm | (25,591,200) | 194,923,284 |
| 25 | Non-Firm | 11,700 | (0) |
| | **Wheeling** | | |
| 26 | Firm | (3,064,705) | 10,884,835 |
| 27 | Non-Firm | 11,979,670 | 4,024,832 |
| | **Generation** | | |
| 28 | Coal | (81,015,519) | 28,276,935 |
| 29 | Seasonal Gas | (839,939) | 3,049,705 |
| 30 | Gas | (36,795,455) | 17,957,360 |
| 31 | Other | 1,449,148 | 1,521,826 |
| | **Other** | | |
| 32 | Cholla/APS | 4,693,888 | 50,052 |
| | **Total** | $ 9,774,547 | $ 100,186,073 |
| | **California Allocated Component Variance** | | |
| | **Wholesale Sales Revenue** | | |
| 33 | Firm | $ (2,426,408) | $ 2,686,466 |
| 34 | Non-Firm | - | 0 |
| | **Purchase Power Expense** | | |
| 35 | Seasonal | - | - |
| 36 | Existing Demand | (146,499) | 35,291 |
| 37 | Existing Energy | (190,900) | 104,483 |
| 38 | QF | 156,848 | 3,731 |
| 39 | Firm | (428,491) | 3,080,635 |
| 40 | Non-Firm | 174 | (0) |
| | **Wheeling** | | |
| 41 | Firm | (48,506) | 172,028 |
| 42 | Non-Firm | 179,659 | 59,981 |
| | **Generation** | | |
| 43 | Coal | (1,236,324) | 421,404 |
| 44 | Seasonal Gas | (539,559) | 267,614 |
| 45 | Gas | (12,485) | 45,449 |
| 46 | Other | 21,473 | 22,679 |
| | **Other** | | |
| 47 | Cholla/APS | 68,760 | 746 |
| 48 | **Total - California Energy Cost Account** | $ 250,559 | $ 1,527,575 |
| 49 | Under (Over) Collection of California NPC | $ 114,316 | $ 2,056,904 |
| 50 | California Energy Cost Adjustment Account Interest | 239 | 1,059 |
| 51 | California Deferred Fuel Stock Carrying Charges | (6,645) | (3,620) |
| 52 | California ARB Administrative Costs | 6,946 | 11,284 |
| 53 | California Net Metering Surplus Compensation | 3,438 | 4,890 |
| 54 | California Renewable Energy Credits Purchases | 155,514 | 81,839 |
| 55 | California Production Tax Credits | 317,278 | 357,476 |
| 56 | California Start-Up Fuel Costs | 1,058 | 4,920 |
| 57 | Total California Balancing Account | $ 592,143 | $ 2,514,751 |

| Line | | 2020 | 2021 | 2022 |
|---|---|---|---|---|
| 58 | **ECAC Balancing Rate $/MWh** | $ 7.35 | $ 1.03 | $ 4.16 |
| 59 | **Billing Factor (Franchise Fees & Uncollectible Accounts)** | 102.1% | 102.1% | 102.1% |
| 60 | **Balancing Rate w Billing Factor $/MWh** | $ 7.50 | $ 1.05 | $ 4.25 |
| 61 | **Balancing Rate Percentage Change** | | | 304.3% |

Application No. 21-08-_____
Exhibit No. PAC/102
Witness: Douglas R. Staples

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP 2022 ECAC

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Net Power Cost Analysis—Adjusted Actual 2020 Net Power Costs

August 2, 2021

**August 2, 2021** **Exhibit PAC/102**

**California ECAC 2020 Adjusted Actual Net Power Cost**

| | Jan-20 | Feb-20 | Mar-20 | Apr-20 | May-20 | Jun-20 | Jul-20 | Aug-20 | Sep-20 | Oct-20 | Nov-20 | Dec-20 | Total 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Special Sales For Resale** | | | | | | | | | | | | | |
| Long Term Firm Sales | | | | | | | | | | | | | |
| Black Hills | $ 123,873 | $ 122,300 | $ 154,273 | $ 245,084 | $ 237,693 | $ 348,302 | $ 364,757 | $ 297,534 | $ 455,758 | $ 332,763 | $ 283,072 | $ 202,932 | $ 3,168,341 |
| Hurricane Sale | - | - | - | - | - | - | - | - | - | 124 | 838 | 987 | 1,948 |
| Leaning Juniper Revenue | 10,124 | 6,857 | 6,304 | (14,714) | 3,427 | 3,726 | 7,994 | 12,426 | 9,695 | 11,652 | 6,961 | 5,008 | 69,459 |
| Total Long Term Firm Sales | $ 133,997 | $ 129,157 | $ 160,577 | $ 230,370 | $ 241,120 | $ 352,028 | $ 372,751 | $ 309,959 | $ 465,453 | $ 344,539 | $ 290,870 | $ 208,927 | $ 3,239,748 |
| Total Short Term Firm Sales | $ 12,152,913 | $ 9,452,766 | $ 11,271,087 | $ 9,043,570 | $ 6,877,358 | $ 9,086,458 | $ 9,140,625 | $ 26,612,932 | $ 16,436,504 | $ 23,182,097 | $ 23,268,422 | $ 14,042,233 | $ 170,566,963 |
| Total Secondary Sales | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Total Special Sales For Resale** | $ 12,286,909 | $ 9,581,923 | $ 11,431,664 | $ 9,273,940 | $ 7,118,478 | $ 9,438,485 | $ 9,513,376 | $ 26,922,891 | $ 16,901,957 | $ 23,526,636 | $ 23,559,292 | $ 14,251,160 | $ 173,806,710 |
| **Purchased Power & Net Interchange** | | | | | | | | | | | | | |
| Long Term Firm Purchases | | | | | | | | | | | | | |
| APS Supplemental | $ 7,656 | $ 129,026 | $ 46,209 | $ 38,115 | $ 15,105 | $ 22,319 | $ 8,082 | $ 17,864 | $ 36,978 | $ 60,290 | $ - | $ - | $ 381,642 |
| Cedar Springs Wind | - | - | - | - | - | - | - | - | 144,348 | 103,096 | 366,878 | 1,371,128 | 1,985,451 |
| Cedar Springs III Wind | - | - | - | - | - | - | - | - | - | - | - | 790,204 | 790,204 |
| Combine Hills Wind | 771,404 | 627,425 | 494,573 | 530,895 | 438,918 | 555,358 | 480,064 | 392,401 | 287,257 | 491,198 | 487,971 | 375,685 | 5,933,148 |
| Cove Mountain Solar | - | - | - | - | - | 16,805 | 28,821 | 28,406 | 287,834 | 237,809 | 214,873 | 170,421 | 984,970 |
| Cove Mountain Solar 2 - FaceBook | - | - | - | - | - | - | 864,426 | 97,116 | 448,844 | 1,140,195 | 477,376 | 353,716 | 3,381,672 |
| Deseret Purchase | 1,349,498 | 4,110,112 | 2,735,686 | 2,243,870 | 2,337,323 | 2,419,443 | 2,737,210 | 2,818,497 | 2,594,351 | 2,585,446 | 2,892,998 | 3,110,120 | 31,934,552 |
| Eagle Mountain - UAMPS/UMPA | 200,110 | 188,937 | 164,535 | 146,988 | 173,905 | 348,612 | 509,979 | 486,884 | 273,464 | 174,394 | 171,795 | 254,986 | 3,094,589 |
| Gemstate | 249,614 | 143,152 | 143,152 | 143,152 | 143,152 | 143,152 | 143,152 | 143,152 | 143,152 | 150,059 | 150,059 | 150,059 | 1,845,007 |
| Hunter Solar | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Hurricane Purchase | 17,892 | 18,207 | 15,120 | 12,537 | 10,395 | 12,285 | 15,498 | 45,386 | 21,924 | 15,183 | 12,587 | 13,963 | 210,977 |
| MagCorp Reserves | 456,648 | 415,376 | 424,897 | 403,523 | 394,001 | 359,303 | 347,916 | 338,609 | 326,594 | 341,818 | 337,345 | 345,617 | 4,491,647 |
| Milford Solar - FaceBook Oregon | - | - | - | - | - | - | - | - | 507,977 | 624,943 | 313,725 | 341,828 | 1,788,472 |
| Millican Solar | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Monsanto Reserves | 1,666,980 | 2,195,172 | 1,207,387 | 1,666,980 | 1,666,980 | 1,666,980 | 1,666,980 | 1,666,980 | 1,666,980 | 1,666,980 | 1,666,980 | 1,666,980 | 20,072,359 |
| Nucor | 600,100 | 600,100 | 600,100 | 600,100 | 600,100 | 600,100 | 600,100 | 600,100 | 600,100 | 600,100 | 600,100 | 600,100 | 7,201,200 |
| Old Mill Solar | 7,278 | 12,945 | 20,306 | 21,899 | 12,977 | 11,484 | 28,399 | 35,061 | 38,760 | 27,684 | 12,240 | 12,116 | 241,148 |
| Pavant III Solar | 42,263 | 50,238 | 85,376 | 78,428 | 75,355 | 138,828 | 248,363 | 993,042 | 292,438 | 133,354 | 70,137 | 45,304 | 2,253,125 |
| PGE Cove | 14,577 | 14,577 | 14,577 | 44,554 | 14,577 | 14,577 | 14,577 | 14,577 | 14,577 | 14,577 | 14,577 | 14,577 | 204,897 |
| Prineville Solar | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Rock River Wind | 735,911 | 597,620 | 468,819 | 427,061 | 296,343 | 346,605 | 258,159 | 203,565 | 351,056 | 522,138 | 601,432 | 554,968 | 5,363,677 |
| Sigurd Solar | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Small Purchases east | 1,797 | 2,296 | 715 | 1,293 | 1,174 | 930 | 1,870 | 2,190 | 2,142 | 2,001 | 2,117 | 2,132 | 20,658 |
| Small Purchases west | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Amor IX - Univ of Utah | 281,289 | 203,062 | 286,212 | 186,450 | 142,351 | 180,280 | 294,055 | 755,241 | 481,890 | 403,017 | 329,033 | 330,462 | 3,873,341 |
| Three Buttes Wind | 2,995,667 | 2,429,761 | 1,890,170 | 1,395,577 | 1,248,905 | 1,518,548 | 1,233,047 | 989,224 | 1,187,815 | 1,575,008 | 2,672,679 | 2,700,072 | 21,836,473 |
| Top of the World Wind | 5,608,891 | 4,420,801 | 3,604,516 | 2,780,215 | 2,691,973 | 2,960,118 | 2,475,755 | 2,056,011 | 2,605,313 | 2,846,002 | 5,265,331 | 5,382,184 | 42,697,110 |
| Tri-State Purchase | 797,495 | 844,338 | 934,368 | 854,690 | 784,038 | - | - | - | - | - | - | - | 4,214,929 |
| Wolverine Creek Wind | 1,434,316 | 947,091 | 1,103,341 | 841,732 | 1,036,903 | 991,355 | 665,313 | 769,186 | 684,879 | 1,129,885 | 1,069,174 | 692,897 | 11,366,071 |
| Long Term Firm Purchases Total | $ 17,239,385 | $ 17,950,234 | $ 14,240,058 | $ 12,418,058 | $ 12,084,474 | $ 12,307,082 | $ 12,621,765 | $ 12,453,492 | $ 12,998,672 | $ 14,845,176 | $ 17,729,406 | $ 19,279,517 | $ 176,167,319 |

**August 2, 2021** **Exhibit PAC/102**

**California ECAC 2020 Adjusted Actual Net Power Cost**

| | Jan-20 | Feb-20 | Mar-20 | Apr-20 | May-20 | Jun-20 | Jul-20 | Aug-20 | Sep-20 | Oct-20 | Nov-20 | Dec-20 | Total 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Qualifying Facilities | | | | | | | | | | | | | |
| QF California | $ 183,858 | $ 163,379 | $ 180,603 | $ 398,425 | $ 325,134 | $ 202,308 | $ 133,036 | $ 131,280 | $ 127,668 | $ 125,472 | $ 84,754 | $ 106,712 | $ 2,162,629 |
| QF Idaho | 573,105 | 403,340 | 559,395 | 618,321 | 848,719 | 755,160 | 725,947 | 560,388 | 522,703 | 586,119 | 549,415 | 593,438 | 7,296,050 |
| QF Oregon | 2,421,973 | 3,135,836 | 3,403,529 | 4,462,036 | 4,439,663 | 4,512,303 | 4,826,585 | 4,073,519 | 3,839,312 | 3,185,370 | 2,302,890 | 2,377,818 | 42,980,834 |
| QF Utah | 681,063 | 761,694 | 790,027 | 912,520 | 947,528 | 856,531 | 831,987 | 824,366 | 794,831 | 778,275 | 608,417 | 636,408 | 9,423,646 |
| QF Washington | - | - | 50 | 18,464 | 34,592 | 48,624 | 62,358 | 61,264 | 35,952 | 7,730 | 2,997 | - | 272,031 |
| QF Wyoming | 6,771 | 4,728 | 8,967 | 1,011 | 466 | 1,090 | 779 | 14,243 | 10,950 | 3,408 | 915 | 970 | 54,297 |
| Biomass One QF | 1,620,090 | 1,407,071 | 1,596,324 | 986,526 | 1,015,188 | 993,155 | 1,460,709 | 1,624,744 | 1,524,593 | 1,574,248 | 1,556,422 | 830,625 | 16,189,695 |
| Chopin Wind QF | 278,752 | 222,808 | 173,957 | 180,669 | 154,061 | 166,831 | 143,243 | 96,748 | 102,457 | 187,633 | 198,071 | 141,448 | 2,046,678 |
| DCFP QF | 302 | 302 | 515 | 317 | 701 | 832 | 2,908 | 9,262 | 5,580 | 3,451 | 1,764 | 924 | 26,858 |
| Enterprise Solar I QF | 672,676 | 891,830 | 839,668 | 1,102,836 | 1,311,732 | 1,401,260 | 1,728,797 | 1,594,388 | 1,165,099 | 879,597 | 688,025 | 583,596 | 12,859,503 |
| Escalante 1 Solar QF | 559,910 | 780,047 | 792,894 | 1,008,612 | 268,234 | 1,203,388 | 1,538,588 | 1,470,768 | 1,110,893 | 925,606 | 624,630 | 421,124 | 10,704,693 |
| Escalante 2 Solar QF | 533,861 | 752,922 | 752,723 | 967,372 | 1,103,019 | 1,162,433 | 1,491,287 | 1,422,941 | 1,059,727 | 883,595 | 590,590 | 425,128 | 11,145,597 |
| Escalante 3 Solar QF | 507,843 | 714,588 | 726,861 | 926,324 | 1,033,660 | 1,112,662 | 1,420,055 | 1,352,658 | 975,327 | 787,684 | 533,723 | 437,942 | 10,529,326 |
| ExxonMobil QF | - | - | 5 | - | - | 1 | - | - | - | - | - | 669 | 675 |
| Five Pine Wind QF | 1,075,796 | 683,657 | 827,739 | 1,370,777 | 682,342 | 1,395,392 | 583,331 | 664,458 | 643,164 | 977,108 | 953,967 | 581,694 | 10,439,425 |
| Foote Creek III Wind QF | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Granite Mountain East Solar QF | 608,384 | 784,013 | 731,967 | 994,105 | 1,164,256 | 1,264,608 | 1,423,209 | 1,311,440 | 1,049,492 | 842,500 | 554,692 | 473,766 | 11,202,434 |
| Granite Mountain West Solar QF | 363,735 | 507,469 | 478,923 | 556,194 | 782,327 | 839,513 | 941,694 | 858,289 | 682,412 | 526,800 | 326,305 | 309,382 | 7,173,042 |
| Iron Springs QF | 629,288 | 826,786 | 777,647 | 1,034,115 | 1,192,618 | 1,300,089 | 1,523,651 | 1,473,637 | 1,082,796 | 875,466 | 585,640 | 514,096 | 11,815,831 |
| Latigo Wind QF | 1,143,809 | 989,580 | 1,014,021 | 772,840 | 587,251 | 901,314 | 691,616 | 718,940 | 585,703 | 721,302 | 866,937 | 936,519 | 9,929,833 |
| Mountain Wind 1 QF | 1,389,897 | 1,230,581 | 628,456 | 687,704 | 497,787 | 554,259 | 625,186 | 512,693 | 680,916 | 1,165,204 | 757,640 | 869,829 | 9,600,152 |
| Mountain Wind 2 QF | 2,235,075 | 1,813,668 | 1,010,863 | 941,628 | 682,380 | 900,228 | 1,060,601 | 763,464 | 947,542 | 1,540,117 | 1,085,069 | 1,239,793 | 14,220,429 |
| North Point Wind QF | 2,286,409 | 1,397,260 | 1,869,436 | 594,282 | 1,431,430 | 647,249 | 1,400,954 | 1,660,716 | 1,509,737 | 2,095,443 | 1,980,997 | 1,319,975 | 18,193,886 |
| Oregon Wind Farm QF | 1,238,458 | 1,448,974 | 1,128,171 | 1,223,967 | 890,758 | 1,482,192 | 1,586,909 | 1,087,508 | 744,750 | 90,374 | 852,389 | 598,316 | 12,372,766 |
| Pavant II Solar QF | 173,788 | 250,424 | 301,537 | 394,659 | 403,668 | 392,691 | 508,449 | 496,047 | 373,864 | 318,263 | 186,588 | 123,365 | 3,923,343 |
| Pioneer Wind 1 QF | 1,676,167 | 1,188,710 | 1,121,337 | 832,424 | 734,811 | 789,306 | 658,848 | 583,060 | 576,169 | 883,248 | 1,421,001 | 1,287,340 | 11,752,419 |
| Power County North Wind QF | 595,491 | 527,010 | 479,809 | 409,540 | 366,929 | 364,890 | 376,636 | 460,498 | 346,650 | 671,824 | 494,964 | 485,186 | 5,579,429 |
| Power County South Wind QF | 571,703 | 492,917 | 444,824 | 380,060 | 332,417 | 317,510 | 307,452 | 368,671 | 320,290 | 673,979 | 446,042 | 411,310 | 5,067,175 |
| Roseburg Dillard QF | 18,636 | 53,193 | (20,062) | 23,995 | 74,334 | (30,511) | 169,846 | 147,331 | 37,608 | 46,940 | 31,954 | 56,701 | 609,964 |
| Sage I Solar QF | 94,700 | 161,183 | 193,397 | 190,000 | 222,522 | 228,252 | 372,488 | 334,141 | 242,254 | 171,072 | 111,954 | 92,244 | 2,414,208 |
| Sage II Solar QF | 104,932 | 170,168 | 195,364 | 153,243 | 224,048 | 229,413 | 364,779 | 335,365 | 248,000 | 172,038 | 112,922 | 92,887 | 2,403,159 |
| Sage III Solar QF | 97,388 | 162,331 | 164,634 | 154,747 | 178,124 | 210,790 | 328,533 | 297,002 | 205,488 | 151,208 | 102,454 | 82,233 | 2,134,932 |
| Spanish Fork Wind 2 QF | 282,276 | 192,165 | 114,723 | 137,896 | 142,838 | 166,448 | 328,144 | 327,553 | 280,033 | 257,974 | 256,790 | 289,048 | 2,775,890 |
| Sunnyside QF | - | - | 1,623,689 | 2,687,285 | 2,432,422 | 2,663,084 | 2,438,990 | 2,964,431 | 2,464,101 | 2,490,145 | 2,513,483 | 2,380,076 | 24,657,707 |
| Sweetwater Solar QF | 341,212 | 575,966 | 623,390 | 795,188 | 828,649 | 825,478 | 959,963 | 851,217 | 660,682 | 510,157 | 355,031 | 290,202 | 7,617,135 |
| Tesoro QF | 4,754 | 58,557 | 39,577 | 12,302 | 2,078 | 2,600 | - | 1,340 | 1,809 | 6,488 | 9,325 | 64,119 | 202,948 |
| Threemile Canyon Wind QF | 140,538 | 203,650 | 187,948 | 193,870 | 180,312 | 242,039 | 236,202 | 179,296 | 96,895 | 183,524 | 118,630 | 86,110 | 2,049,012 |
| Three Peaks Solar QF | 488,073 | 676,114 | 667,494 | 914,738 | 1,017,161 | 947,561 | 1,192,847 | 1,156,922 | 944,767 | 838,984 | 529,424 | 423,476 | 9,797,561 |
| Utah Pavant Solar QF | 213,073 | 281,796 | 351,379 | 458,277 | 536,411 | 577,874 | 704,952 | 727,891 | 585,205 | 443,325 | 264,573 | 153,176 | 5,297,932 |
| Utah Red Hills Solar QF | 555,155 | 790,387 | 802,756 | 1,050,186 | 1,306,651 | 1,295,915 | 1,686,833 | 1,655,233 | 1,503,406 | 928,539 | 657,078 | 493,273 | 12,725,414 |
| Qualifying Facilities Total | $ 24,368,940 | $ 24,705,103 | $ 25,584,540 | $ 28,547,454 | $ 28,377,220 | $ 30,924,761 | $ 34,838,390 | $ 33,173,711 | $ 28,088,825 | $ 27,510,211 | $ 23,318,462 | $ 20,210,921 | $ 329,648,537 |
| Mid-Columbia Contracts | | | | | | | | | | | | | |
| Grant Reasonable | (247,879) | (247,879) | (511,021) | (247,879) | (247,879) | (247,879) | (247,879) | (247,879) | (247,879) | (247,879) | (247,879) | (247,879) | (3,237,686) |
| Grant Surplus | 173,914 | 173,914 | 59,445 | 173,914 | 173,914 | 173,914 | 173,914 | 173,914 | 173,914 | 173,914 | 173,914 | 173,914 | 1,972,501 |
| Mid-Columbia Contracts Total | $ (73,964) | $ (73,964) | $ (451,576) | $ (73,965) | $ (73,965) | $ (73,965) | $ (73,965) | $ (73,965) | $ (73,965) | $ (73,965) | $ (73,965) | $ (73,965) | $ (1,265,185) |
| Total Long Term Firm Purchases | $ 41,534,360 | $ 42,581,372 | $ 39,373,022 | $ 40,891,547 | $ 40,387,729 | $ 43,157,879 | $ 47,386,191 | $ 45,553,238 | $ 41,013,532 | $ 42,281,422 | $ 40,973,903 | $ 39,416,474 | $ 504,550,670 |
| Storage & Exchange | | | | | | | | | | | | | |
| APS Exchange | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Cowlitz Swift | - | - | - | - | - | - | - | - | - | - | - | - | - |
| PSCo Exchange | 450,000 | 450,000 | 450,000 | 450,000 | 450,000 | 450,000 | 450,000 | 450,000 | 450,000 | 450,000 | 450,000 | 450,000 | 5,400,000 |
| SCL State Line | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Total Storage & Exchange | $ 450,000 | $ 450,000 | $ 450,000 | $ 450,000 | $ 450,000 | $ 450,000 | $ 450,000 | $ 450,000 | $ 450,000 | $ 450,000 | $ 450,000 | $ 450,000 | $ 5,400,000 |
| Total Short Term Firm Purchases | $ (143,940) | $ 9,510,475 | $ 13,707,213 | $ 4,795,532 | $ 12,381,196 | $ 13,399,289 | $ 28,995,064 | $ 29,700,139 | $ 6,265,378 | $ 4,901,226 | $ 5,679,637 | $ 5,003,776 | $ 134,194,985 |
| Total Secondary Purchases | 0 | - | 1,598 | 102 | (0) | 0 | (0) | 0 | (0) | (0) | 10,000 | (0) | 11,700 |
| **Total Purchased Power & Net Interchange** | $ 41,840,420 | $ 52,541,847 | $ 53,531,833 | $ 46,137,181 | $ 53,218,925 | $ 57,007,169 | $ 76,831,255 | $ 75,703,377 | $ 47,728,911 | $ 47,632,648 | $ 47,113,540 | $ 44,870,250 | $ 644,157,356 |
| **Wheeling & U. of F. Expense** | | | | | | | | | | | | | |
| Firm Wheeling | $ 11,398,268 | $ 11,175,784 | $ 10,910,806 | $ 10,623,632 | $ 10,037,630 | $ 10,264,443 | $ 10,672,700 | $ 10,405,925 | $ 10,225,763 | $ 10,891,286 | $ 11,014,515 | $ 11,181,539 | $ 128,802,293 |
| Non-Firm Wheeling | 788,114 | 505,483 | 1,071,400 | 1,175,770 | 442,029 | 1,035,360 | 1,251,970 | 1,608,500 | 788,312 | 1,076,399 | 901,238 | 1,428,833 | 12,073,409 |
| **Total Wheeling & U. of F. Expense** | $ 12,186,382 | $ 11,681,267 | $ 11,982,206 | $ 11,799,403 | $ 10,479,659 | $ 11,299,804 | $ 11,924,670 | $ 12,014,425 | $ 11,014,075 | $ 11,967,685 | $ 11,915,754 | $ 12,610,372 | $ 140,875,701 |

**August 2, 2021**

**Exhibit PAC/102**

**California ECAC 2020 Adjusted Actual Net Power Cost**

| | Jan-20 | Feb-20 | Mar-20 | Apr-20 | May-20 | Jun-20 | Jul-20 | Aug-20 | Sep-20 | Oct-20 | Nov-20 | Dec-20 | Total 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Coal Fuel Burn Expense** | | | | | | | | | | | | | |
| Cholla | 3,492,143 | (8,032) | - | - | 2,997,317 | 6,601,807 | 4,751,321 | 6,648,300 | 5,194,143 | 5,250,654 | 4,789,128 | 4,357,160 | 44,073,940 |
| Colstrip | 1,636,443 | 1,589,897 | 1,549,366 | 1,482,156 | 795,810 | 817,226 | 1,514,194 | 1,716,063 | 1,052,798 | 449,281 | 818,558 | 1,371,947 | 14,793,738 |
| Craig | 2,888,380 | 1,441,534 | 2,219,621 | 2,021,008 | 2,117,777 | 1,414,540 | 1,662,626 | 1,776,376 | 1,270,149 | 1,386,850 | 1,523,168 | 2,195,429 | 21,917,457 |
| Dave Johnston | 3,587,676 | 3,682,248 | 4,148,522 | 3,804,432 | 3,551,438 | 3,486,175 | 4,005,326 | 4,117,931 | 3,045,426 | 3,395,598 | 4,087,058 | 3,611,517 | 44,523,346 |
| Hayden | 736,475 | 575,443 | 1,034,110 | 796,321 | 555,878 | 741,642 | 1,036,768 | 876,100 | 449,589 | 507,248 | 533,341 | 796,744 | 8,639,658 |
| Hunter | 10,780,441 | 8,976,185 | 7,158,101 | 8,899,789 | 8,452,865 | 10,549,583 | 11,467,568 | 13,116,743 | 11,523,315 | 11,504,777 | 11,961,935 | 12,007,826 | 126,399,129 |
| Huntington | 7,727,400 | 5,931,466 | 7,837,301 | 5,229,260 | 4,845,656 | 5,430,453 | 5,710,881 | 9,844,196 | 11,840,704 | 9,737,869 | 8,848,516 | 10,886,093 | 93,869,793 |
| Jim Bridger | 15,651,941 | 13,380,083 | 18,625,712 | 12,893,151 | 11,691,061 | 13,340,810 | 15,350,552 | 18,048,565 | 15,452,746 | 19,534,186 | 17,361,197 | 15,364,336 | 186,694,341 |
| Naughton 1 & 2 | 6,652,895 | 6,085,117 | 6,383,166 | 5,145,286 | 4,443,034 | 5,508,661 | 6,908,361 | 5,868,839 | 3,680,878 | 6,973,733 | 6,604,464 | 6,871,983 | 71,126,415 |
| Wyodak | 1,484,065 | 1,485,973 | 1,617,959 | 1,762,593 | 1,753,632 | 1,446,486 | 1,901,394 | 2,198,614 | 1,780,368 | 1,338,906 | 1,819,529 | 2,273,022 | 20,862,541 |
| **Total Coal Fuel Burn Expense** | $ 54,637,858 | $ 43,139,914 | $ 50,573,857 | $ 42,033,994 | $ 41,204,468 | $ 49,337,383 | $ 54,308,989 | $ 64,211,726 | $ 55,290,116 | $ 60,079,102 | $ 58,346,895 | $ 59,736,056 | $ 632,900,359 |
| **Gas Fuel Burn Expense** | | | | | | | | | | | | | |
| Chehalis | $ 6,922,036 | $ 4,540,837 | $ 6,017,687 | $ 3,444,006 | $ 3,189,609 | $ 2,069,773 | $ 4,009,995 | $ 4,705,602 | $ 5,113,343 | $ 7,126,668 | $ 5,018,602 | $ 5,857,943 | $ 58,016,102 |
| Currant Creek | 5,973,766 | 4,383,603 | 441,765 | 3,504,739 | 3,920,117 | 3,292,369 | 4,441,413 | 4,515,285 | 4,907,761 | 4,538,448 | 3,673,860 | 5,548,220 | 49,141,345 |
| Gadsby | 18,641 | - | - | - | 74,092 | 317,379 | 1,088,927 | 1,645,594 | 1,017,987 | 328,014 | 282 | - | 4,490,915 |
| Gadsby CT | 169,237 | 163,592 | 281,151 | 154,506 | 130,616 | 71,121 | 119,357 | 678,669 | 284,216 | 114,001 | 117,133 | 118,041 | 2,401,639 |
| Hermiston | 2,503,297 | 1,902,753 | 1,975,478 | 1,549,099 | 230,308 | 1,675,333 | 1,412,592 | 2,438,857 | 2,237,327 | 1,924,837 | 3,054,011 | 3,343,085 | 24,246,976 |
| Lake Side 1 | 6,401,528 | 5,047,011 | 4,574,420 | 458,073 | 3,669,609 | 3,347,979 | 5,990,779 | 5,315,230 | 4,941,439 | 4,282,589 | 3,265,441 | 6,321,411 | 53,615,508 |
| Lake Side 2 | 4,811,225 | 6,716,288 | 8,836,213 | 5,057,814 | 2,457,163 | 4,650,058 | 4,767,743 | 6,357,360 | 5,530,244 | 5,587,938 | 4,971,653 | 5,455,513 | 65,199,212 |
| Naughton 3 | 2,994 | 2,994 | 2,973 | 2,994 | 2,994 | 2,994 | 756,205 | 2,595,619 | 1,152,618 | 717,705 | 591,807 | 153,880 | 5,985,779 |
| **Total Gas Fuel Burn Expense** | $ 26,802,723 | $ 22,757,079 | $ 22,129,686 | $ 14,171,230 | $ 13,674,509 | $ 15,427,005 | $ 22,587,011 | $ 28,252,216 | $ 25,184,935 | $ 24,620,200 | $ 20,692,789 | $ 26,798,093 | $ 263,097,477 |
| **Other Generation** | | | | | | | | | | | | | |
| Black Cap Solar | $ 1,974 | $ 3,602 | $ 5,432 | $ 5,933 | $ 3,534 | $ 2,857 | $ 10,211 | $ 12,334 | $ 14,033 | $ 9,958 | $ 4,103 | $ 4,629 | $ 78,600 |
| Blundell | 343,791 | 1,740,154 | 774,881 | 355,231 | 336,559 | 319,057 | 345,026 | 408,695 | 347,683 | 343,093 | 309,424 | 390,421 | 6,014,015 |
| Wind Integration Charge | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Total Other Generation** | $ 345,765 | $ 1,743,756 | $ 780,313 | $ 361,164 | $ 340,093 | $ 321,913 | $ 355,237 | $ 421,029 | $ 361,716 | $ 353,051 | $ 313,527 | $ 395,051 | $ 6,092,615 |
| **Net Power Cost** | $ 123,526,238 | $ 122,281,941 | $ 127,566,231 | $ 105,229,033 | $ 111,799,176 | $ 123,954,789 | $ 156,493,785 | $ 153,679,882 | $ 122,677,796 | $ 121,126,050 | $ 114,823,213 | $ 130,158,662 | $ 1,513,316,797 |
| **Net Power Cost/Net System Load** | $24.09 | $25.98 | $26.00 | $25.52 | $24.77 | $26.46 | $27.86 | $26.93 | $26.18 | $26.35 | $24.00 | $23.98 | |

August 2, 2021 | Exhibit PAC/102

**California ECAC 2020 Adjusted Actual Net Power Cost**

| | Jan-20 | Feb-20 | Mar-20 | Apr-20 | May-20 | Jun-20 | Jul-20 | Aug-20 | Sep-20 | Oct-20 | Nov-20 | Dec-20 | Total 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Net System Load** | 5,127,035 | 4,706,249 | 4,906,272 | 4,123,565 | 4,513,495 | 4,685,230 | 5,617,190 | 5,706,644 | 4,685,752 | 4,596,457 | 4,784,309 | 5,427,314 | 58,879,512 |
| **Special Sales For Resale** | | | | | | | | | | | | | |
| Long Term Firm Sales | | | | | | | | | | | | | |
| Black Hills | 2,002 | 2,272 | 3,515 | 7,935 | 8,580 | 13,247 | 14,056 | 10,751 | 18,530 | 12,483 | 10,015 | 6,100 | 109,488 |
| Hurricane Sale | - | - | - | - | - | - | - | - | - | 2 | 20 | 20 | 41 |
| Total Long Term Firm Sales | 2,002 | 2,272 | 3,515 | 7,935 | 8,580 | 13,247 | 14,056 | 10,751 | 18,530 | 12,485 | 10,035 | 6,120 | 109,529 |
| Total Short Term Firm Sales | 412,274 | 335,214 | 304,794 | 362,605 | 259,999 | 415,409 | 258,007 | 340,496 | 330,563 | 704,951 | 685,465 | 476,132 | 4,885,911 |
| Total Secondary Sales | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Total Special Sales For Resale** | 414,276 | 337,486 | 308,310 | 370,540 | 268,579 | 428,656 | 272,063 | 351,247 | 349,093 | 717,436 | 695,500 | 482,252 | 4,995,440 |
| **Total Requirements** | 5,541,311 | 5,043,735 | 5,214,582 | 4,494,105 | 4,782,074 | 5,113,886 | 5,889,253 | 6,057,892 | 5,034,845 | 5,313,893 | 5,479,810 | 5,909,566 | 63,874,952 |
| **Purchased Power & Net Interchange** | | | | | | | | | | | | | |
| Long Term Firm Purchases | | | | | | | | | | | | | |
| APS Supplemental | 600 | 5,250 | 1,800 | 1,500 | 600 | 900 | 300 | 600 | 1,500 | 1,950 | - | - | 15,000 |
| Cedar Springs Wind | - | - | - | - | - | - | - | - | 11,881 | 8,865 | 31,546 | 93,241 | 145,532 |
| Cedar Springs III Wind | - | - | - | - | - | - | - | - | - | - | - | 46,700 | 46,700 |
| Combine Hills Wind | 15,622 | 28,583 | 10,106 | 20,687 | 8,971 | 11,349 | 9,812 | 8,018 | (19,591) | 10,037 | 9,971 | 7,676 | 121,240 |
| Cove Mountain Solar | - | - | - | - | - | 928 | 1,591 | 1,568 | 15,891 | 13,130 | 8,897 | 7,057 | 49,063 |
| Cove Mountain Solar 2 - FaceBook | - | - | - | - | - | - | 20,393 | 507 | 7,331 | 26,837 | 18,516 | 13,880 | 87,463 |
| Deseret Purchase | 39,878 | 25,120 | 32,746 | 12,090 | 16,015 | 19,464 | 32,810 | 36,224 | 26,810 | 26,436 | 39,353 | 48,472 | 355,418 |
| Eagle Mountain - UAMPS/UMPA | 4,136 | 3,880 | 3,388 | 3,296 | 4,120 | 7,254 | 8,776 | 8,032 | 5,200 | 3,720 | 3,654 | 5,296 | 60,752 |
| Gemstate | - | - | - | - | 10,568 | 15,903 | 13,478 | 11,422 | - | - | - | - | 51,371 |
| Hunter Solar | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Hurricane Purchase | 256 | 260 | 216 | 179 | 149 | 176 | 221 | 648 | 313 | 217 | 181 | 206 | 3,022 |
| MagCorp Reserves | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Milford Solar - FaceBook Oregon | - | - | - | - | - | - | - | - | 11,704 | 18,537 | 14,814 | 13,112 | 58,167 |
| Millican Solar | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Monsanto Reserves | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Nucor | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Old Mill Solar | 309 | 770 | 882 | 1,234 | 1,328 | 1,420 | 1,697 | 1,040 | 1,082 | 863 | 484 | 412 | 11,521 |
| Pavant III Solar | 2,232 | 3,314 | 3,993 | 5,002 | 5,628 | 5,640 | 5,985 | 5,794 | 4,779 | 3,127 | 2,720 | 1,778 | 49,993 |
| PGE Cove | 1,019 | 953 | 1,018 | 986 | 1,019 | 986 | 1,019 | 1,019 | 986 | 1,019 | 988 | 1,013 | 12,026 |
| Prineville Solar | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Rock River Wind | 20,742 | 16,844 | 13,214 | 12,037 | 8,352 | 9,769 | 7,276 | 5,737 | 9,894 | 14,716 | 16,951 | 15,642 | 151,175 |
| Sigurd Solar | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Small Purchases east | 16 | 24 | (0) | 11 | 10 | 7 | 55 | 22 | 23 | 21 | 23 | 25 | 237 |
| Small Purchases west | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Amor IX - Univ of Utah | 13,807 | 12,787 | 13,287 | 11,683 | 10,850 | 8,063 | 8,184 | 5,806 | 8,026 | 11,037 | 12,538 | 12,705 | 128,773 |
| Three Buttes Wind | 47,095 | 38,299 | 29,773 | 21,914 | 19,575 | 23,802 | 19,327 | 15,505 | 18,619 | 24,689 | 41,950 | 42,335 | 342,883 |
| Top of the World Wind | 55,483 | 51,305 | 41,447 | 32,389 | 31,903 | 31,027 | 34,619 | 28,466 | 30,622 | 38,472 | 74,655 | 68,860 | 519,249 |
| Tri-State Purchase | 8,632 | 10,080 | 12,863 | 10,400 | 8,216 | - | - | - | - | - | - | - | 50,191 |
| Wolverine Creek Wind | 23,398 | 15,450 | 17,999 | 13,731 | 16,915 | 16,172 | 10,853 | 12,548 | 11,173 | 18,432 | 17,442 | 11,303 | 185,417 |
| Long Term Firm Purchases Total | 233,225 | 212,919 | 182,730 | 147,140 | 144,221 | 152,860 | 176,397 | 142,958 | 146,244 | 222,104 | 294,681 | 389,713 | 2,445,191 |

**August 2, 2021** **Exhibit PAC/102**

**California ECAC 2020 Adjusted Actual Net Power Cost**

| | Jan-20 | Feb-20 | Mar-20 | Apr-20 | May-20 | Jun-20 | Jul-20 | Aug-20 | Sep-20 | Oct-20 | Nov-20 | Dec-20 | Total 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Qualifying Facilities | | | | | | | | | | | | | |
| QF California | 2,971 | 1,776 | 4,087 | 4,492 | 3,694 | 4,141 | 3,248 | 3,157 | 3,164 | 2,995 | 2,720 | 2,878 | 39,323 |
| QF Idaho | 9,766 | 7,249 | 9,305 | 10,444 | 14,555 | 13,070 | 11,460 | 8,614 | 8,366 | 9,127 | 8,900 | 9,166 | 120,023 |
| QF Oregon | 29,850 | 43,473 | 48,270 | 62,949 | 64,697 | 66,239 | 71,740 | 61,599 | 52,823 | 45,429 | 31,312 | 31,452 | 609,834 |
| QF Utah | 6,908 | 8,138 | 8,644 | 10,858 | 11,630 | 10,227 | 10,746 | 10,641 | 9,817 | 9,041 | 5,805 | 6,328 | 108,782 |
| QF Washington | - | - | 2 | 488 | 870 | 1,202 | 1,541 | 1,513 | 890 | 252 | - | - | 6,759 |
| QF Wyoming | 312 | 221 | 512 | 63 | 22 | 59 | 23 | 530 | 472 | 203 | 60 | 56 | 2,534 |
| Biomass One QF | 20,454 | 17,790 | 20,118 | 28,582 | (28,582) | - | 18,650 | 20,414 | 19,217 | 19,760 | 19,739 | 10,434 | 166,576 |
| Chopin Wind QF | 4,819 | 3,843 | 2,972 | 3,078 | 2,743 | 3,006 | 2,532 | 1,751 | 1,805 | 3,300 | 3,343 | 2,378 | 35,568 |
| DCFP QF | 18 | 20 | 23 | 18 | 71 | 98 | 152 | 186 | 100 | 116 | 72 | 34 | 907 |
| Enterprise Solar I QF | 12,415 | 16,400 | 17,424 | 22,182 | 26,289 | 26,483 | 27,338 | 25,121 | 20,750 | 16,824 | 12,804 | 10,912 | 234,941 |
| Escalante 1 Solar QF | 10,542 | 14,637 | 16,789 | 20,684 | 5,532 | 23,196 | 24,771 | 23,614 | 20,194 | 18,042 | 11,848 | 8,062 | 197,911 |
| Escalante 2 Solar QF | 10,565 | 14,849 | 16,765 | 20,855 | 23,766 | 23,551 | 25,279 | 24,058 | 20,264 | 18,116 | 11,764 | 8,545 | 218,379 |
| Escalante 3 Solar QF | 10,299 | 14,397 | 16,642 | 20,488 | 22,698 | 23,102 | 24,745 | 23,489 | 19,163 | 17,596 | 11,568 | 9,554 | 213,740 |
| ExxonMobil QF | - | - | 0 | - | - | 0 | - | - | - | - | - | 37 | 37 |
| Foote Creek III Wind QF | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Five Pine Wind QF | 12,302 | 9,449 | 11,657 | 20,073 | 10,978 | 21,787 | 6,632 | 7,117 | 7,577 | 10,882 | 11,298 | 5,682 | 135,432 |
| Granite Mountain East Solar QF | 11,208 | 14,584 | 15,125 | 20,579 | 24,661 | 24,588 | 23,592 | 23,031 | 20,337 | 17,431 | 11,294 | 9,400 | 215,828 |
| Granite Mountain West Solar QF | 6,375 | 8,979 | 9,395 | 10,924 | 15,759 | 15,529 | 14,814 | 14,351 | 12,590 | 10,382 | 6,339 | 5,849 | 131,286 |
| Iron Springs QF | 11,277 | 14,961 | 15,610 | 20,784 | 24,571 | 24,613 | 24,527 | 23,616 | 20,498 | 17,694 | 11,648 | 9,958 | 219,758 |
| Latigo Wind QF | 18,267 | 16,685 | 17,731 | 13,905 | 11,117 | 15,796 | 9,350 | 9,818 | 9,483 | 12,389 | 14,547 | 14,400 | 163,488 |
| Mountain Wind 1 QF | 22,781 | 21,291 | 11,828 | 14,394 | 9,893 | 10,974 | 9,580 | 7,479 | 11,888 | 22,103 | 14,172 | 15,075 | 171,459 |
| Mountain Wind 2 QF | 32,290 | 28,071 | 16,558 | 17,591 | 12,199 | 14,254 | 11,864 | 8,827 | 14,152 | 27,006 | 17,863 | 19,046 | 219,720 |
| North Point Wind QF | 26,129 | 19,415 | 26,423 | 8,676 | 23,249 | 9,988 | 16,112 | 17,865 | 17,836 | 23,381 | 23,506 | 12,894 | 225,473 |
| Oregon Wind Farm QF | 15,588 | 17,776 | 13,981 | 15,061 | 11,259 | 18,882 | 19,999 | 13,871 | 9,435 | 1,228 | 10,473 | 7,393 | 154,946 |
| Pavant II Solar QF | 5,555 | 8,001 | 9,884 | 12,286 | 13,710 | 14,054 | 14,454 | 14,080 | 11,779 | 10,090 | 6,429 | 4,094 | 124,414 |
| Pioneer Wind 1 QF | 43,271 | 29,245 | 27,576 | 19,730 | 17,926 | 18,666 | 14,608 | 12,178 | 16,681 | 22,417 | 36,305 | 33,956 | 292,559 |
| Power County North Wind QF | 8,225 | 6,426 | 6,742 | 5,937 | 5,887 | 5,736 | 4,311 | 4,954 | 4,093 | 7,449 | 5,835 | 4,707 | 70,303 |
| Power County South Wind QF | 7,113 | 6,003 | 6,244 | 5,473 | 5,316 | 4,983 | 3,481 | 3,960 | 3,780 | 7,470 | 5,235 | 3,993 | 63,049 |
| Roseburg Dillard QF | 1,044 | 2,194 | (206) | 1,713 | 3,091 | (27) | 4,909 | 5,650 | 1,945 | 2,885 | 2,383 | 2,929 | 28,511 |
| Sage I Solar QF | 1,926 | 3,262 | 4,348 | 4,894 | 5,704 | 5,525 | 6,824 | 5,838 | 4,875 | 3,882 | 2,522 | 2,003 | 51,602 |
| Sage II Solar QF | 2,131 | 3,440 | 4,388 | 3,941 | 5,737 | 5,544 | 6,661 | 5,853 | 4,985 | 3,901 | 2,540 | 2,015 | 51,135 |
| Sage III Solar QF | 1,993 | 3,306 | 3,724 | 4,013 | 4,596 | 5,139 | 6,058 | 5,220 | 4,164 | 3,451 | 2,321 | 1,796 | 45,783 |
| Spanish Fork Wind 2 QF | 4,543 | 3,205 | 2,028 | 2,651 | 2,743 | 2,892 | 4,851 | 4,735 | 4,567 | 4,622 | 4,505 | 4,805 | 46,146 |
| Sunnyside QF | - | - | 19,331 | 37,105 | 32,222 | 36,653 | 32,275 | 38,264 | 28,792 | 33,014 | 33,654 | 30,987 | 322,298 |
| Sweetwater Solar QF | 7,855 | 13,030 | 14,868 | 19,796 | 21,342 | 19,819 | 21,051 | 18,166 | 14,858 | 11,532 | 8,671 | 6,960 | 177,948 |
| Tesoro QF | 233 | 2,837 | 1,888 | 605 | 97 | 109 | - | 63 | 80 | 300 | 472 | 3,059 | 9,743 |
| Three Peaks Solar QF | 11,718 | 16,178 | 16,425 | 21,730 | 26,073 | 24,609 | 25,357 | 24,458 | 21,112 | 19,204 | 12,342 | 10,614 | 229,822 |
| Threemile Canyon Wind QF | 1,768 | 2,485 | 2,278 | 2,331 | 2,239 | 3,011 | 2,913 | 2,232 | 1,201 | 2,248 | 1,438 | 1,055 | 25,199 |
| Utah Pavant Solar QF | 5,218 | 7,295 | 9,386 | 12,215 | 14,005 | 13,717 | 14,028 | 13,392 | 11,278 | 9,404 | 6,015 | 3,369 | 119,323 |
| Utah Red Hills Solar QF | 11,102 | 14,278 | 15,445 | 20,058 | 24,549 | 24,579 | 24,474 | 23,955 | 20,094 | 17,423 | 11,269 | 9,740 | 216,965 |
| Qualifying Facilities Total | 388,829 | 415,189 | 444,209 | 521,647 | 476,908 | 535,795 | 544,947 | 513,656 | 455,104 | 462,588 | 383,016 | 325,614 | 5,467,504 |
| Mid-Columbia Contracts | | | | | | | | | | | | | |
| Grant Reasonable | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Grant Surplus | 8,742 | 9,691 | 7,211 | 6,206 | 10,947 | 10,673 | 10,909 | 8,851 | 5,876 | 5,476 | 8,085 | 8,904 | 101,571 |
| Mid-Columbia Contracts Total | 8,742 | 9,691 | 7,211 | 6,206 | 10,947 | 10,673 | 10,909 | 8,851 | 5,876 | 5,476 | 8,085 | 8,904 | 101,571 |
| Total Long Term Firm Purchases | 630,796 | 637,800 | 634,150 | 674,992 | 632,076 | 699,329 | 732,253 | 665,465 | 607,223 | 690,168 | 685,783 | 724,232 | 8,014,267 |
| Storage & Exchange | | | | | | | | | | | | | |
| APS Exchange | 137,679 | 69,785 | - | - | (75,678) | (140,898) | (142,848) | (142,848) | (69,119) | 77,414 | 137,293 | 142,804 | (6,416) |
| BPA FC IV Wind | (680) | 989 | (1,127) | (145) | (1,694) | 508 | (1,022) | (1,546) | 1,076 | (2,141) | (7) | - | (5,789) |
| Cowlitz Swift | (9,483) | (19,187) | (19,615) | 13,483 | 13,437 | 218 | (537) | (6,245) | 1,861 | 6,131 | (2,759) | (1,469) | (24,165) |
| PSCo Exchange | 7 | 345 | 108 | - | - | 25 | 396 | (584) | (277) | 103 | 171 | 16 | 310 |
| SCL State Line | 36,774 | 27,834 | (11,007) | (8,809) | (3,348) | 2,188 | (164) | (9,169) | (18,892) | 8,172 | 20,504 | (10,834) | 33,249 |
| Total Storage & Exchange | 164,297 | 79,765 | (31,640) | 4,529 | (67,283) | (137,959) | (144,175) | (160,392) | (85,350) | 89,679 | 155,202 | 130,517 | (2,811) |
| Total Short Term Firm Purchases | 83,084 | 417,006 | 730,422 | 619,908 | 881,227 | 958,026 | 1,126,869 | 692,647 | 195,584 | 59,453 | 233,581 | 204,575 | 6,202,383 |
| Total Secondary Purchases | (1,666) | 421 | 545 | (2,069) | (200) | 424 | 841 | (3,285) | 147 | 2,936 | 1,358 | 955 | 407 |
| **Total Purchased Power & Net Interchange** | 876,512 | 1,134,992 | 1,333,477 | 1,297,360 | 1,445,820 | 1,519,820 | 1,715,788 | 1,194,434 | 717,604 | 842,236 | 1,075,924 | 1,060,278 | 14,214,245 |

**August 2, 2021** **Exhibit PAC/102**

**California ECAC 2020 Adjusted Actual Net Power Cost**

| | Jan-20 | Feb-20 | Mar-20 | Apr-20 | May-20 | Jun-20 | Jul-20 | Aug-20 | Sep-20 | Oct-20 | Nov-20 | Dec-20 | Total 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Coal Generation** | | | | | | | | | | | | | |
| Cholla | 143,675 | (2,548) | (2,576) | (2,022) | 118,638 | 197,684 | 189,598 | 265,352 | 214,515 | 213,335 | 191,874 | 141,949 | 1,669,474 |
| Colstrip | 106,692 | 95,429 | 95,462 | 92,006 | 44,736 | 46,996 | 83,091 | 100,995 | 52,005 | 27,258 | 48,446 | 93,210 | 886,326 |
| Craig | 107,578 | 106,277 | 96,743 | 103,595 | 108,059 | 85,397 | 90,471 | 94,550 | 78,866 | 61,025 | 83,026 | 107,171 | 1,122,758 |
| Dave Johnston | 346,740 | 361,559 | 400,543 | 379,269 | 342,015 | 327,613 | 394,796 | 408,345 | 295,220 | 323,172 | 403,833 | 342,499 | 4,325,604 |
| Hayden | 32,482 | 29,404 | 39,952 | 32,164 | 23,652 | 33,069 | 42,865 | 47,007 | 29,828 | 22,025 | 22,926 | 37,212 | 392,586 |
| Hunter | 600,488 | 489,209 | 399,289 | 335,206 | 581,498 | 553,587 | 606,657 | 715,597 | 632,740 | 653,445 | 683,201 | 692,899 | 6,943,816 |
| Huntington | 427,002 | 294,269 | 355,643 | 218,200 | 199,237 | 233,254 | 263,359 | 488,036 | 599,764 | 487,478 | 420,147 | 528,916 | 4,515,305 |
| Jim Bridger | 636,825 | 487,356 | 682,302 | 445,372 | 401,658 | 453,219 | 591,793 | 685,429 | 583,543 | 765,205 | 680,782 | 593,205 | 7,006,689 |
| Naughton 1 & 2 | 234,031 | 213,517 | 223,050 | 178,999 | 146,680 | 192,787 | 235,686 | 196,362 | 138,073 | 252,607 | 241,427 | 253,998 | 2,507,217 |
| Wyodak | 93,541 | 83,974 | 86,839 | 97,892 | 96,514 | 101,874 | 116,774 | 128,716 | 116,938 | 96,881 | 125,247 | 119,848 | 1,265,038 |
| **Total Coal Generation** | 2,729,054 | 2,158,446 | 2,377,247 | 1,880,681 | 2,062,687 | 2,225,480 | 2,615,090 | 3,130,389 | 2,741,492 | 2,902,431 | 2,900,909 | 2,910,907 | 30,634,813 |
| **Gas Generation** | | | | | | | | | | | | | |
| Chehalis | 222,194 | 151,343 | 282,619 | 213,674 | 168,104 | 84,048 | 180,007 | 227,545 | 263,807 | 271,530 | 157,944 | 184,704 | 2,407,519 |
| Currant Creek | 272,283 | 193,825 | (1,023) | 147,204 | 195,292 | 172,293 | 222,980 | 224,302 | 258,471 | 217,276 | 171,639 | 260,884 | 2,335,426 |
| Gadsby | (488) | (346) | (248) | (234) | 377 | 4,021 | 22,530 | 39,998 | 20,037 | 5,375 | (339) | (350) | 90,333 |
| Gadsby CT | 626 | 717 | 2,938 | 131 | 1,061 | 1,418 | 2,995 | 22,291 | 8,092 | 2,348 | 274 | 186 | 43,077 |
| Hermiston | 145,858 | 131,421 | 154,602 | 122,672 | (482) | 127,460 | 96,967 | 142,389 | 140,731 | 100,834 | 138,295 | 152,772 | 1,453,519 |
| Lake Side 1 | 281,115 | 210,466 | 151,982 | (608) | 179,527 | 175,816 | 244,509 | 275,668 | 238,777 | 195,891 | 146,804 | 288,248 | 2,388,195 |
| Lake Side 2 | 199,759 | 304,612 | 334,338 | 232,649 | 126,034 | 252,268 | 329,456 | 359,671 | 282,210 | 265,006 | 247,656 | 238,258 | 3,171,917 |
| Naughton 3 | (1,065) | (943) | (946) | (848) | (808) | (882) | 27,229 | 83,654 | 21,116 | 16,256 | 10,081 | (1,028) | 151,816 |
| **Total Gas Generation** | 1,120,282 | 991,095 | 924,262 | 714,640 | 669,105 | 816,442 | 1,126,673 | 1,375,518 | 1,233,241 | 1,074,516 | 872,354 | 1,123,674 | 12,041,802 |
| **Hydro Generation** | | | | | | | | | | | | | |
| West Hydro | 394,395 | 355,913 | 174,977 | 269,629 | 301,943 | 218,812 | 136,232 | 103,396 | 76,291 | 140,974 | 216,456 | 297,411 | 2,686,429 |
| East Hydro | 25,504 | 31,154 | 58,175 | 39,664 | 33,831 | 33,426 | 39,020 | 37,335 | 19,127 | 9,906 | 11,379 | 12,282 | 350,803 |
| **Total Hydro Generation** | 419,899 | 387,067 | 233,152 | 309,293 | 335,774 | 252,238 | 175,252 | 140,731 | 95,418 | 150,880 | 227,835 | 309,693 | 3,037,232 |
| **Other Generation** | | | | | | | | | | | | | |
| Black Cap Solar | 83 | 213 | 235 | 334 | 361 | 325 | 614 | 366 | 391 | 311 | 162 | 156 | 3,553 |
| Blundell | 7,961 | 7,134 | 13,502 | 13,031 | 12,209 | 11,463 | 11,549 | 16,758 | 19,642 | 21,042 | 21,768 | 19,511 | 175,570 |
| Cedar Springs II Wind | - | - | - | - | - | - | - | - | - | - | - | 64,482 | 64,482 |
| Dunlap I Wind | 60,609 | 46,685 | 36,220 | 21,945 | 20,354 | 22,743 | 10,233 | 72 | 24,018 | 43,220 | 46,716 | 55,427 | 388,242 |
| Ekola Flats Wind | - | - | - | - | - | - | - | - | - | - | - | 36,054 | 36,054 |
| Foote Creek I Wind | 16,307 | 13,066 | 10,225 | 7,848 | 1,752 | - | - | - | - | - | - | (2) | 49,196 |
| Glenrock Wind | 52,485 | 40,579 | 33,537 | 26,979 | 27,309 | 28,196 | 24,745 | 21,583 | 24,019 | 29,979 | 45,731 | 47,627 | 402,769 |
| Glenrock III Wind | 19,908 | 16,158 | 13,200 | 10,030 | 10,149 | 10,598 | 9,258 | 7,960 | 8,907 | 11,059 | 18,814 | 18,587 | 154,628 |
| Goodnoe Wind | 26,451 | 28,233 | 28,568 | 28,362 | 28,572 | 33,922 | 30,811 | 26,412 | 20,365 | 29,984 | 25,135 | 20,017 | 326,832 |
| High Plains Wind | 49,796 | 40,849 | 33,028 | 17,002 | 20,082 | 27,343 | 22,328 | 17,036 | 27,225 | 29,136 | 39,813 | 35,177 | 358,815 |
| Leaning Juniper 1 | 22,753 | 30,930 | 24,427 | 27,870 | 29,336 | 35,431 | 34,567 | 30,507 | 17,425 | 28,121 | 20,575 | 14,426 | 316,368 |
| Marengo I Wind | 8,332 | 42,033 | 44,018 | 46,791 | 39,581 | 42,751 | 35,911 | 33,033 | 28,170 | 46,301 | 46,543 | 35,244 | 448,708 |
| Marengo II Wind | 10 | 2,585 | 20,265 | 23,659 | 17,462 | 20,183 | 18,501 | 16,724 | 14,174 | 24,991 | 23,170 | 18,398 | 200,122 |
| McFadden Ridge Wind | 14,533 | 12,272 | 10,023 | 5,163 | 6,188 | 8,673 | 7,216 | 5,509 | 8,552 | 8,865 | 12,126 | 10,152 | 109,272 |
| Pryor Mountain Wind | - | - | - | - | - | - | - | - | - | - | - | 259 | 259 |
| Rolling Hills Wind | 49,332 | 38,304 | 31,320 | 23,105 | 23,618 | 23,746 | 21,352 | 18,017 | 20,394 | 26,116 | 45,092 | 42,825 | 363,221 |
| Seven Mile Wind | 55,113 | 44,136 | 39,416 | 32,953 | 26,115 | 28,439 | 24,076 | 18,774 | 27,918 | 37,054 | 47,108 | 46,754 | 427,856 |
| Seven Mile II Wind | 11,891 | 8,958 | 8,460 | 7,058 | 5,601 | 6,093 | 5,289 | 4,068 | 5,890 | 7,651 | 10,034 | 9,803 | 90,796 |
| TB Flats Wind | - | - | - | - | - | - | - | - | - | - | - | 30,117 | 30,117 |
| TB Flats Wind II | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Total Other Generation** | 395,564 | 372,135 | 346,444 | 292,130 | 268,689 | 299,906 | 256,450 | 216,819 | 247,090 | 343,830 | 402,787 | 505,014 | 3,946,860 |
| **Total Resources** | 5,541,311 | 5,043,735 | 5,214,582 | 4,494,105 | 4,782,074 | 5,113,886 | 5,889,253 | 6,057,892 | 5,034,845 | 5,313,893 | 5,479,810 | 5,909,566 | 63,874,952 |

Application No. 21-08-_____
Exhibit No. PAC/103
Witness: Douglas R. Staples

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP 2022 ECAC

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Net Power Cost Analysis—Adjusted Actual/Projected 2021 Net Power Costs

August 2, 2021

## California ECAC 2021 Adjusted Actual / Projected Net Power Cost

Exhibit PAC/103

| | Jan-21 | Feb-21 | Mar-21 | Apr-21 | May-21 | Jun-21 | Jul-21 | Aug-21 | Sep-21 | Oct-21 | Nov-21 | Dec-21 | Total 2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Special Sales For Resale** | | | | | | | | | | | | | |
| Long Term Firm Sales | | | | | | | | | | | | | |
| Black Hills | $ 303,229 | $ 335,305 | $ 321,392 | $ 558,272 | $ 387,470 | $ 610,430 | $ 743,275 | $ 684,290 | $ 702,097 | $ 711,911 | $ 674,483 | $ 732,145 | $ 6,764,299 |
| Hurricane Sale | 917 | 1,007 | 981 | 1,040 | 1,052 | 540 | 540 | 540 | 540 | 540 | 540 | 540 | 8,774 |
| Leaning Juniper Revenue | 2,905 | 14,706 | 6,344 | (15,819) | 13,203 | 7,715 | 21,897 | 24,824 | 16,289 | 9,678 | 7,498 | 8,946 | 118,186 |
| Total Long Term Firm Sales | $ 307,050 | $ 351,018 | $ 328,718 | $ 543,493 | $ 401,725 | $ 618,685 | $ 765,712 | $ 709,653 | $ 718,925 | $ 722,129 | $ 682,520 | $ 741,631 | $ 6,891,259 |
| Total Short Term Firm Sales | $ 12,802,582 | $ 19,180,290 | $ 12,820,867 | $ 12,088,533 | $ 12,305,306 | $ 30,710,601 | $ 44,224,745 | $ 51,140,983 | $ 57,933,661 | $ 37,912,859 | $ 38,462,703 | $ 40,762,844 | $ 370,345,972 |
| Total Secondary Sales | - | - | - | (574) | 574 | - | - | - | - | - | - | - | 0 |
| **Total Special Sales For Resale** | $ 13,109,632 | $ 19,531,308 | $ 13,149,584 | $ 12,631,452 | $ 12,707,604 | $ 31,329,286 | $ 44,990,456 | $ 51,850,637 | $ 58,652,587 | $ 38,634,988 | $ 39,145,223 | $ 41,504,475 | $ 377,237,231 |
| **Purchased Power & Net Interchange** | | | | | | | | | | | | | |
| Long Term Firm Purchases | | | | | | | | | | | | | |
| Cedar Springs Wind | $ 1,433,834 | $ 923,575 | $ 960,172 | $ 902,074 | $ 881,041 | $ 1,026,445 | $ 1,060,660 | $ 1,060,660 | $ 1,026,445 | $ 1,060,660 | $ 1,026,445 | $ 1,060,660 | $ 12,422,674 |
| Cedar Springs III Wind | 1,139,707 | 760,648 | 772,525 | 750,440 | 686,074 | 779,959 | 805,958 | 805,958 | 779,959 | 805,958 | 779,959 | 805,958 | 9,673,102 |
| Combine Hills Wind | 441,377 | 547,648 | 534,512 | 320,257 | 426,978 | 401,855 | 448,041 | 381,825 | 356,540 | 373,462 | 455,099 | 566,954 | 5,254,549 |
| Cove Mountain Solar | 190,930 | 242,729 | 278,918 | 398,429 | 479,605 | 457,334 | 443,628 | 419,764 | 359,961 | 289,769 | 208,202 | 171,172 | 3,940,440 |
| Cove Mountain Solar 2 - FaceBook | 385,337 | 1,823,808 | 532,580 | 999,222 | 1,112,306 | 1,136,848 | 1,102,776 | 1,043,455 | 894,797 | 720,312 | 514,667 | 423,130 | 10,689,238 |
| Deseret Purchase | 3,027,849 | 2,998,638 | 2,940,119 | 2,136,040 | 2,231,134 | 2,552,753 | 2,979,150 | 2,979,150 | 2,947,854 | 2,946,551 | 2,674,022 | 2,936,119 | 33,349,377 |
| Eagle Mountain - UAMPS/UMPA | 199,301 | 182,309 | 165,365 | 146,988 | 173,900 | 284,602 | 436,746 | 407,436 | 241,072 | 156,349 | 153,678 | 228,970 | 2,776,717 |
| Gemstate | 150,059 | 150,059 | 100,610 | 150,059 | 150,059 | 143,152 | 143,152 | 143,152 | 143,152 | 143,152 | 143,152 | 143,152 | 1,702,910 |
| Graphite Solar | - | - | - | - | - | - | - | - | - | - | - | 8,726 | 8,726 |
| Hunter Solar | - | 547,744 | 609,120 | 972,486 | 732,774 | 797,428 | 758,093 | 712,634 | 664,479 | 567,050 | 402,182 | 326,655 | 7,090,645 |
| Hurricane Purchase | 19,381 | 18,481 | 14,769 | 14,362 | 9,631 | 14,960 | 14,960 | 14,960 | 14,960 | 14,960 | 14,960 | 14,960 | 181,341 |
| MagCorp Reserves | 344,048 | 327,810 | 348,804 | 334,330 | 345,704 | 409,020 | 413,030 | 392,980 | 388,970 | 372,930 | 433,080 | 413,030 | 4,523,737 |
| Millican Solar | - | 206,916 | 237,604 | 299,843 | 238,432 | 333,291 | 375,334 | 331,656 | 266,914 | 174,771 | 111,940 | 76,815 | 2,653,514 |
| Milford Solar - FaceBook Oregon | 382,777 | 417,936 | 1,041,907 | 822,901 | 992,045 | 839,927 | 747,990 | 720,079 | 671,702 | 541,718 | 394,119 | 310,565 | 7,883,666 |
| Monsanto Reserves | 1,666,980 | 2,129,243 | 1,666,980 | 1,666,980 | 1,666,980 | 1,666,667 | 1,666,667 | 1,666,667 | 1,666,667 | 1,666,667 | 1,666,667 | 1,666,667 | 20,463,829 |
| Nucor | 609,450 | 609,450 | 609,450 | 609,450 | 609,450 | 594,150 | 594,150 | 594,150 | 594,150 | 594,150 | 594,150 | 594,150 | 7,206,300 |
| Old Mill Solar | 9,205 | 24,272 | 27,821 | 52,993 | 49,003 | - | - | - | - | - | - | - | 163,295 |
| Pavant III Solar | 55,373 | 216,957 | 76,730 | 146,763 | 159,334 | - | - | - | - | - | - | - | 655,157 |
| PGE Cove | 11,759 | (46,518) | 11,759 | 11,759 | 11,759 | 12,899 | 12,899 | 12,899 | 12,899 | 12,899 | 12,899 | 12,899 | 90,810 |
| Prineville Solar | - | 146,111 | 149,700 | 207,280 | 221,207 | 221,430 | 249,362 | 220,343 | 177,331 | 116,113 | 74,370 | 51,034 | 1,834,280 |
| Rock River Wind | 514,018 | 596,926 | 434,722 | 371,360 | 267,012 | - | - | - | - | - | - | - | 2,184,037 |
| Sigurd Solar | - | - | 124,859 | 634,220 | 646,182 | 710,144 | 660,236 | 605,233 | 565,052 | 458,516 | 322,228 | 270,678 | 4,997,348 |
| Small Purchases east | 2,597 | 2,527 | 2,225 | 2,088 | 1,776 | 1,203 | 1,226 | 1,202 | 1,153 | 1,157 | 1,209 | 1,176 | 19,539 |
| Small Purchases west | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Amor IX - Univ of Utah | 279,473 | 882,740 | 300,666 | 343,932 | 289,796 | - | - | - | - | - | - | - | 2,096,608 |
| Three Buttes Wind | 2,117,297 | 1,630,150 | 1,356,865 | 1,352,336 | 1,305,728 | 1,205,304 | 804,843 | 950,802 | 1,185,464 | 1,741,196 | 2,346,698 | 2,701,069 | 18,697,752 |
| Top of the World Wind | 4,767,549 | 3,123,515 | 2,566,302 | 2,696,323 | 2,341,146 | 2,398,843 | 1,719,857 | 1,873,298 | 2,296,246 | 3,519,349 | 4,486,125 | 4,898,057 | 36,686,608 |
| UT Solar Adjustment | - | - | - | - | - | (969,285) | (936,120) | (876,799) | (728,316) | (581,664) | (376,089) | (293,208) | (4,761,482) |
| Wolverine Creek Wind | 766,984 | 1,320,589 | 700,446 | 764,877 | 768,206 | 840,940 | 669,552 | 639,635 | 751,599 | 830,847 | 959,867 | 958,779 | 9,972,322 |
| Long Term Firm Purchases Total | $ 18,515,284 | $ 19,784,265 | $ 16,565,530 | $ 17,107,792 | $ 16,797,263 | $ 15,859,867 | $ 15,172,187 | $ 15,101,137 | $ 15,279,050 | $ 16,526,870 | $ 17,399,629 | $ 18,348,165 | $ 202,457,041 |

**California ECAC 2021 Adjusted Actual / Projected Net Power Cost** | **Exhibit PAC/103**

| | Jan-21 | Feb-21 | Mar-21 | Apr-21 | May-21 | Jun-21 | Jul-21 | Aug-21 | Sep-21 | Oct-21 | Nov-21 | Dec-21 | Total 2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Qualifying Facilities | | | | | | | | | | | | | |
| QF California | $ 221,601 | $ 48,270 | $ 164,620 | $ 168,092 | $ 36,616 | $ 264,043 | $ 176,178 | $ 142,348 | $ 133,461 | $ 136,480 | $ 142,828 | $ 182,897 | $ 1,817,435 |
| QF Idaho | 579,590 | 497,260 | 527,841 | 481,396 | 471,320 | 499,723 | 459,624 | 383,689 | 347,836 | 380,400 | 363,144 | 355,298 | 5,347,122 |
| QF Oregon | 2,258,810 | 2,623,728 | 3,467,267 | 4,326,432 | 4,354,576 | 5,764,450 | 5,462,940 | 5,158,550 | 4,431,711 | 3,490,075 | 2,540,086 | 2,703,410 | 46,582,035 |
| QF Utah | 712,402 | 740,809 | 915,015 | 1,054,867 | 1,121,192 | 1,155,089 | 1,078,375 | 1,069,489 | 1,003,757 | 958,244 | 845,671 | 770,935 | 11,425,844 |
| QF Washington | - | - | - | 19,952 | 44,511 | 49,280 | 55,428 | 1,643 | 24,365 | 2,049 | - | - | 197,227 |
| QF Wyoming | 1,246 | 239 | 165 | 4,464 | 3,750 | 8,827 | 14,385 | 13,362 | 10,012 | 11,949 | 12,179 | 15,981 | 96,559 |
| Biomass One QF | 1,696,738 | 1,527,609 | 1,709,402 | 1,562,477 | 1,095,609 | 459,606 | 1,436,000 | 1,431,519 | 1,370,863 | 1,467,011 | 1,401,172 | 811,834 | 15,969,839 |
| Chopin Wind QF | 137,530 | 200,109 | 170,883 | 148,761 | 151,238 | | | | | | | | 808,522 |
| DCFP QF | 592 | 524 | 114 | 657 | 1,451 | 7,210 | 30,046 | 39,670 | 30,987 | 12,667 | 5,484 | 5,436 | 134,837 |
| Enterprise Solar I QF | 623,646 | 764,831 | 890,957 | 1,098,416 | 1,313,623 | 1,382,054 | 1,552,203 | 1,505,433 | 1,180,042 | 955,809 | 706,377 | 545,566 | 12,518,958 |
| Escalante 1 Solar QF | 561,587 | 646,998 | 841,344 | 1,059,930 | 1,227,781 | 1,306,559 | 1,438,731 | 1,385,249 | 1,095,951 | 874,775 | 643,296 | 508,060 | 11,590,260 |
| Escalante 2 Solar QF | 534,943 | 618,177 | 810,357 | 1,007,925 | 1,173,473 | 1,235,528 | 1,359,543 | 1,300,450 | 1,032,836 | 820,378 | 601,838 | 473,100 | 10,968,548 |
| Escalante 3 Solar QF | 522,145 | 596,589 | 775,452 | 974,230 | 1,131,106 | 1,206,417 | 1,320,931 | 1,265,996 | 1,003,819 | 750,960 | 551,605 | 434,576 | 10,533,826 |
| ExxonMobil QF | - | - | 290 | - | - | - | - | - | - | - | - | - | 290 |
| Five Pine Wind QF | 483,993 | 810,782 | 977,282 | 517,726 | 493,220 | 538,166 | 621,525 | 599,633 | 746,134 | 737,773 | 876,316 | 873,556 | 8,276,106 |
| Granite Mountain East Solar QF | 564,331 | 695,085 | 866,815 | 1,034,570 | 1,212,293 | 1,259,680 | 1,335,982 | 1,265,220 | 977,968 | 810,379 | 582,140 | 467,391 | 11,071,853 |
| Granite Mountain West Solar QF | 366,409 | 453,525 | 563,445 | 691,414 | 808,994 | 833,309 | 885,762 | 835,986 | 646,535 | 536,651 | 384,176 | 309,016 | 7,315,223 |
| Iron Springs QF | 578,535 | 709,286 | 880,171 | 1,068,170 | 1,257,705 | 1,284,495 | 1,347,967 | 1,321,760 | 1,005,036 | 816,736 | 579,100 | 499,587 | 11,348,547 |
| Latigo Wind QF | 950,514 | 972,355 | 1,024,751 | 934,273 | 774,454 | 745,769 | 682,129 | 567,674 | 618,825 | 807,122 | 702,995 | 746,997 | 9,527,858 |
| Mountain Wind 1 QF | 999,815 | 1,302,186 | 455,339 | 621,159 | 424,948 | 506,044 | 409,953 | 441,735 | 457,892 | 678,977 | 905,337 | 1,069,619 | 8,273,003 |
| Mountain Wind 2 QF | 1,465,418 | 1,868,666 | 746,805 | 923,115 | 645,203 | 916,030 | 758,096 | 735,904 | 761,711 | 1,017,825 | 1,404,943 | 1,586,724 | 12,830,440 |
| North Point Wind QF | 1,101,200 | 1,879,791 | 476,857 | 1,067,388 | 899,032 | 1,219,941 | 1,445,365 | 1,484,098 | 1,774,582 | 1,714,383 | 1,862,305 | 1,807,583 | 16,732,525 |
| Orchard Wind 1 QF | - | 45,119 | 34,541 | 51,246 | 47,398 | | | | | | | | 178,303 |
| Orchard Wind 2 QF | - | 34,138 | 27,791 | 45,254 | 49,099 | | | | | | | | 156,282 |
| Orchard Wind 3 QF | - | 31,288 | 39,070 | 50,669 | 47,074 | | | | | | | | 168,101 |
| Orchard Wind 4 QF | - | 41,308 | 41,358 | 45,823 | 45,500 | | | | | | | | 173,990 |
| Oregon Wind Farm QF | 418,043 | 1,346,268 | 1,041,011 | 1,133,335 | 1,138,541 | 1,232,548 | 1,244,072 | 1,126,416 | 899,250 | 731,888 | 804,124 | 1,034,862 | 12,150,358 |
| Pavant II Solar QF | 193,761 | 205,128 | 286,500 | 417,817 | 450,291 | 478,033 | 553,909 | 543,142 | 422,777 | 330,485 | 205,538 | 166,658 | 4,254,038 |
| Pioneer Wind 1 QF | 1,388,301 | 1,008,856 | 904,826 | 695,187 | 558,974 | 739,286 | 855,024 | 824,438 | 540,837 | 865,851 | 1,351,367 | 1,086,498 | 10,819,446 |
| Power County North Wind QF | 432,606 | 633,391 | 356,350 | 457,227 | 357,166 | 351,208 | 367,188 | 365,344 | 379,222 | 513,261 | 524,964 | 604,018 | 5,341,943 |
| Power County South Wind QF | 405,028 | 618,917 | 326,158 | 416,898 | 322,967 | 312,828 | 324,499 | 340,451 | 335,797 | 449,413 | 473,672 | 523,696 | 4,850,323 |
| Roseburg Dillard QF | 101,680 | 341,461 | 224,851 | 137,079 | 198,871 | 88,024 | 184,094 | 164,917 | 71,575 | 73,646 | 74,283 | 62,700 | 1,723,180 |
| Sage I Solar QF | 111,289 | 137,681 | 169,581 | 194,054 | 193,006 | 262,709 | 337,883 | 333,611 | 208,547 | 155,711 | 104,870 | 75,399 | 2,284,341 |
| Sage II Solar QF | 113,038 | 141,427 | 187,015 | 180,987 | 213,850 | 263,006 | 338,244 | 333,977 | 208,784 | 155,870 | 105,000 | 75,469 | 2,316,665 |
| Sage III Solar QF | 102,542 | 126,464 | 133,314 | 176,845 | 200,780 | 214,874 | 275,731 | 272,050 | 172,117 | 130,624 | 88,886 | 64,050 | 1,958,276 |
| Spanish Fork Wind 2 QF | 283,806 | 109,605 | 164,766 | 175,108 | 142,543 | 214,368 | 288,600 | 313,056 | 271,942 | 241,047 | 250,345 | 260,335 | 2,715,521 |
| Sunnyside QF | 2,627,831 | 2,879,970 | 2,638,554 | 1,782,052 | 2,705,638 | 2,925,018 | 2,977,195 | 2,990,479 | 2,754,883 | 2,426,677 | 2,713,367 | 2,519,596 | 31,941,259 |
| Sweetwater Solar QF | 362,232 | 467,615 | 644,118 | 758,040 | 823,194 | 985,566 | 1,121,978 | 1,038,739 | 815,928 | 628,053 | 300,112 | 202,134 | 8,147,708 |
| Tesoro QF | 351 | 3,196 | 3,864 | 787 | 4 | 11,120 | 15,475 | 26,432 | 13,690 | 10,948 | 14,520 | 67,165 | 167,551 |
| Threemile Canyon Wind QF | 54,700 | 210,276 | 160,200 | 190,691 | 187,435 | - | - | - | - | - | - | - | 803,301 |
| Three Peaks Solar QF | 453,340 | 581,098 | 762,238 | 961,028 | 1,070,544 | 913,116 | 1,045,097 | 1,002,590 | 793,842 | 671,675 | 444,511 | 371,805 | 9,070,884 |
| Utah Pavant Solar QF | 256,837 | 227,505 | 339,298 | 458,410 | 563,726 | 655,441 | 750,517 | 705,242 | 589,010 | 448,089 | 276,633 | 228,636 | 5,499,344 |
| Utah Red Hills Solar QF | 545,996 | 667,739 | 901,256 | 1,120,239 | 1,359,417 | 1,228,925 | 1,501,650 | 1,444,794 | 1,308,209 | 807,396 | 588,016 | 463,540 | 11,937,178 |
| Qualifying Facilities Total | $ 22,212,426 | $ 26,815,266 | $ 25,651,831 | $ 28,214,190 | $ 29,318,116 | $ 31,518,287 | $ 34,052,315 | $ 32,775,083 | $ 28,440,729 | $ 25,621,277 | $ 23,431,201 | $ 21,974,128 | $ 330,024,851 |
| Mid-Columbia Contracts | | | | | | | | | | | | | |
| Grant Reasonable | (177,927) | (177,927) | (172,532) | (177,927) | (177,927) | (174,928) | (174,928) | (174,928) | (174,928) | (174,928) | (174,928) | (174,928) | (2,108,740) |
| Grant Meaningful Priority | - | - | - | - | - | 2,396,350 | 2,396,350 | 2,396,350 | 2,396,350 | 2,396,350 | 2,396,350 | 2,396,350 | 16,774,450 |
| Grant - Priest Rapids | - | - | - | - | - | 179,999 | 179,999 | 179,999 | 179,999 | 179,999 | 179,999 | 179,999 | 1,259,990 |
| Grant Surplus | 179,999 | 179,999 | 182,639 | 179,999 | 179,999 | - | - | - | - | - | - | - | 902,633 |
| Mid-Columbia Contracts Total | $ 2,071 | $ 2,071 | $ 10,107 | $ 2,071 | $ 2,071 | $ 2,401,420 | $ 2,401,420 | $ 2,401,420 | $ 2,401,420 | $ 2,401,420 | $ 2,401,420 | $ 2,401,420 | $ 16,828,333 |
| Total Long Term Firm Purchases | $ 40,729,782 | $ 46,601,602 | $ 42,227,469 | $ 45,324,053 | $ 46,117,450 | $ 49,779,575 | $ 51,625,923 | $ 50,277,641 | $ 46,121,200 | $ 44,549,568 | $ 43,232,250 | $ 42,723,714 | $ 549,310,225 |
| Storage & Exchange | | | | | | | | | | | | | |
| APS Exchange | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Cowlitz Swift | - | - | - | - | - | - | - | - | - | - | - | - | - |
| PSCo Exchange | 450,000 | 450,000 | 450,000 | 450,000 | 450,000 | 450,000 | 450,000 | 450,000 | 450,000 | 450,000 | 450,000 | 450,000 | 5,400,000 |
| SCL State Line | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Total Storage & Exchange | $ 450,000 | $ 450,000 | $ 450,000 | $ 450,000 | $ 450,000 | $ 450,000 | $ 450,000 | $ 450,000 | $ 450,000 | $ 450,000 | $ 450,000 | $ 450,000 | $ 5,400,000 |
| Total Short Term Firm Purchases | $ 622,856 | $ (1,451,860) | $ 1,553,503 | $ 4,042,601 | $ 1,297,350 | $ 29,495,459 | $ 54,024,039 | $ 48,579,797 | $ 45,332,368 | $ 20,416,962 | $ 22,352,195 | $ 38,009,404 | $ 264,274,675 |
| Total Secondary Purchases | (0) | 0 | (0) | - | (0) | - | - | - | - | - | - | - | (0) |
| **Total Purchased Power & Net Interchange** | $ 41,802,638 | $ 45,599,741 | $ 44,230,972 | $ 49,816,654 | $ 47,864,800 | $ 79,725,034 | $ 106,099,962 | $ 99,307,438 | $ 91,903,567 | $ 65,416,530 | $ 66,034,445 | $ 81,183,118 | $ 818,984,901 |

| | Jan-21 | Feb-21 | Mar-21 | Apr-21 | May-21 | Jun-21 | Jul-21 | Aug-21 | Sep-21 | Oct-21 | Nov-21 | Dec-21 | Total 2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Wheeling & U. of F. Expense** | | | | | | | | | | | | | |
| Firm Wheeling | $ 11,493,377 | $ 11,108,659 | $ 13,450,471 | $ 11,841,156 | $ 11,408,855 | $ 12,515,748 | $ 13,136,192 | $ 13,207,889 | $ 12,237,905 | $ 13,556,533 | $ 13,763,344 | $ 14,450,504 | $ 152,170,631 |
| Non-Firm Wheeling | 722,668 | 823,495 | 584,110 | 1,121,297 | 815,179 | - | - | - | - | - | - | - | 4,066,750 |
| **Total Wheeling & U. of F. Expense** | $ 12,216,045 | $ 11,932,154 | $ 14,034,580 | $ 12,962,453 | $ 12,224,034 | $ 12,515,748 | $ 13,136,192 | $ 13,207,889 | $ 12,237,905 | $ 13,556,533 | $ 13,763,344 | $ 14,450,504 | $ 156,237,381 |

**California ECAC 2021 Adjusted Actual / Projected Net Power Cost** | **Exhibit PAC/103**

| | Jan-21 | Feb-21 | Mar-21 | Apr-21 | May-21 | Jun-21 | Jul-21 | Aug-21 | Sep-21 | Oct-21 | Nov-21 | Dec-21 | Total 2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Coal Fuel Burn Expense** | | | | | | | | | | | | | |
| Cholla | $ 50,052 | $ (0) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 50,052 |
| Colstrip | 1,676,659 | 1,291,056 | 1,772,641 | 883,247 | 978,180 | 1,257,726 | 1,391,091 | 1,502,581 | 1,341,323 | 881,539 | 972,981 | 1,279,218 | 15,228,244 |
| Craig | 2,329,341 | 1,938,368 | 2,151,511 | 2,196,588 | 2,168,336 | 993,658 | 1,286,988 | 1,736,454 | 1,696,648 | 1,614,256 | 1,620,509 | 1,637,543 | 21,370,200 |
| Dave Johnston | 3,494,883 | 3,563,370 | 3,434,747 | 2,398,185 | 3,907,782 | 3,061,127 | 3,148,630 | 3,862,967 | 3,536,775 | 3,731,418 | 3,313,266 | 3,830,663 | 41,283,813 |
| Hayden | 1,028,217 | 859,283 | 924,916 | 805,494 | 621,625 | 1,151,301 | 1,124,865 | 940,923 | 687,372 | 998,816 | 1,023,878 | 1,078,313 | 11,245,003 |
| Hunter | 12,085,636 | 10,061,518 | 10,880,002 | 10,110,989 | 10,068,337 | 8,148,804 | 8,928,729 | 9,160,929 | 8,235,630 | 9,319,084 | 9,661,064 | 9,939,343 | 116,600,065 |
| Huntington | 9,133,847 | 9,080,817 | 9,459,295 | 9,943,160 | 10,234,964 | 8,163,071 | 9,083,307 | 9,090,557 | 7,980,224 | 7,513,914 | 8,568,867 | 10,531,131 | 108,783,156 |
| Jim Bridger | 13,390,769 | 14,008,681 | 18,003,236 | 13,551,678 | 17,069,185 | 12,345,855 | 20,905,667 | 20,768,489 | 18,454,193 | 17,676,396 | 17,619,929 | 17,548,198 | 201,342,274 |
| Naughton 1 & 2 | 6,877,365 | 5,212,414 | 5,616,908 | 2,876,136 | 4,391,958 | 6,234,293 | 6,793,048 | 6,916,170 | 6,631,793 | 7,213,564 | 6,220,823 | 6,171,471 | 71,155,943 |
| Wyodak | 1,928,353 | 1,144,054 | 1,827,439 | 1,458,613 | 1,565,618 | 1,959,649 | 2,566,990 | 2,322,782 | 2,129,181 | 2,215,861 | 1,550,015 | 1,203,515 | 21,872,069 |
| **Total Coal Fuel Burn Expense** | $ 51,995,124 | $ 47,159,560 | $ 54,070,695 | $ 44,224,089 | $ 51,005,986 | $ 43,315,485 | $ 55,229,315 | $ 56,301,852 | $ 50,693,140 | $ 51,164,848 | $ 50,551,330 | $ 53,219,396 | $ 608,930,820 |
| **Gas Fuel Burn Expense** | | | | | | | | | | | | | |
| Chehalis | $ 5,927,705 | $ 6,853,641 | $ 6,441,153 | $ 6,318,969 | $ 3,017,204 | $ 2,583,669 | $ 5,200,069 | $ 4,865,059 | $ 4,939,343 | $ 6,221,244 | $ 4,815,189 | $ 5,960,784 | $ 63,144,030 |
| Currant Creek | 6,107,319 | 6,973,961 | 5,244,474 | 4,371,186 | 4,721,089 | 4,564,084 | 5,877,006 | 3,959,564 | 3,648,744 | 4,626,173 | 6,602,888 | 4,970,802 | 61,667,288 |
| Gadsby | 82,147 | (268) | - | - | 107,482 | 580,490 | 741,992 | 853,498 | 804,234 | 664,379 | 652,787 | 1,215,769 | 5,702,509 |
| Gadsby CT | 25,446 | 123,680 | 122,009 | 135,801 | 69,809 | 362,436 | 652,500 | 636,821 | 621,608 | 670,841 | 589,619 | 1,125,992 | 5,136,562 |
| Hermiston | 2,835,397 | 4,249,790 | 2,694,088 | 916,890 | 2,938,272 | 542,306 | 1,772,897 | 1,726,116 | 2,041,262 | 1,421,992 | 1,754,669 | 2,114,640 | 25,008,318 |
| Lake Side 1 | 5,536,856 | 6,591,792 | 5,211,116 | 5,172,789 | 4,922,549 | 3,668,677 | 5,604,278 | 5,471,648 | 4,628,620 | 5,439,508 | 5,905,722 | 5,012,647 | 63,166,203 |
| Lake Side 2 | 5,910,133 | 6,780,030 | 4,593,730 | 4,454,220 | 5,767,034 | 2,754,251 | 3,346,377 | 3,105,439 | 3,035,739 | 3,479,287 | 4,208,768 | 4,626,287 | 52,061,294 |
| Naughton 3 | 201,162 | 749,619 | 204,615 | 1,697,214 | 1,219,155 | 909,548 | 1,528,427 | 1,596,527 | 1,144,701 | 1,464,514 | 1,042,253 | 3,267,689 | 15,025,425 |
| **Total Gas Fuel Burn Expense** | $ 26,626,164 | $ 32,322,245 | $ 24,511,185 | $ 23,067,071 | $ 22,762,594 | $ 15,965,460 | $ 24,723,545 | $ 22,214,671 | $ 20,864,251 | $ 23,987,938 | $ 25,571,896 | $ 28,294,610 | $ 290,911,630 |
| **Other Generation** | | | | | | | | | | | | | |
| Black Cap Solar | $ 3,158 | $ 8,508 | $ 7,272 | $ 13,091 | $ 10,560 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 42,589 |
| Blundell Bottoming Cycle | - | - | - | - | - | 165,082 | 170,510 | 170,557 | 165,117 | 169,735 | 108,592 | 127,851 | 1,077,444 |
| Blundell | 343,918 | 386,078 | 398,944 | 460,677 | 471,818 | 414,321 | 384,162 | 406,143 | 424,511 | 415,482 | 229,466 | 246,405 | 4,581,924 |
| **Total Other Generation** | $ 347,075 | $ 394,586 | $ 406,216 | $ 473,767 | $ 482,378 | $ 579,403 | $ 554,672 | $ 576,700 | $ 589,628 | $ 585,218 | $ 338,058 | $ 374,256 | $ 5,701,958 |
| **Net Power Cost** | $ 119,877,413 | $ 117,876,978 | $ 124,104,065 | $ 117,912,584 | $ 121,632,187 | $ 120,771,845 | $ 154,753,230 | $ 139,757,913 | $ 117,635,903 | $ 116,076,080 | $ 117,113,850 | $ 136,017,409 | $ 1,503,529,458 |

Application No. 21-08-_____
Exhibit No. PAC/104
Witness: Douglas R. Staples

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP 2022 ECAC

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Net Power Cost Analysis—Projected 2022 Net Power Costs

August 2, 2021

**California ECAC 2022 Projected Net Power Cost** **Exhibit PAC/104**

| | Jan-22 | Feb-22 | Mar-22 | Apr-22 | May-22 | Jun-22 | Jul-22 | Aug-22 | Sep-22 | Oct-22 | Nov-22 | Dec-22 | Total 2022 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Special Sales For Resale** | | | | | | | | | | | | | |
| Long Term Firm Sales | | | | | | | | | | | | | |
| Black Hills | $ 684,840 | $ 651,124 | $ 715,551 | $ 463,545 | $ 406,679 | $ 605,206 | $ 733,040 | $ 701,878 | $ 674,345 | $ 684,072 | $ 695,621 | $ 734,640 | $ 7,750,540 |
| Hurricane Sale | 540 | 540 | 540 | 540 | 540 | 540 | 540 | 540 | 540 | 540 | 540 | 540 | 6,475 |
| Leaning Juniper Revenue | 8,068 | 7,601 | 9,462 | 4,912 | 3,927 | 6,910 | 17,829 | 20,473 | 14,692 | 8,897 | 6,870 | 7,937 | 117,580 |
| Total Long Term Firm Sales | $ 693,448 | $ 659,264 | $ 725,552 | $ 468,997 | $ 411,145 | $ 612,656 | $ 751,409 | $ 722,891 | $ 689,576 | $ 693,508 | $ 703,030 | $ 743,117 | $ 7,874,595 |
| Total Short Term Firm Sales | $ 34,565,384 | $ 21,049,559 | $ 25,445,540 | $ 14,920,294 | $ 14,509,669 | $ 20,741,744 | $ 31,185,816 | $ 36,713,145 | $ 33,215,983 | $ 25,401,937 | $ 20,735,335 | $ 17,930,656 | $ 296,415,062 |
| Total Secondary Sales | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Total Special Sales For Resale** | $ 35,258,832 | $ 21,708,823 | $ 26,171,092 | $ 15,389,292 | $ 14,920,814 | $ 21,354,399 | $ 31,937,225 | $ 37,436,037 | $ 33,905,559 | $ 26,095,446 | $ 21,438,365 | $ 18,673,773 | $ 304,289,657 |
| **Purchased Power & Net Interchange** | | | | | | | | | | | | | |
| Long Term Firm Purchases | | | | | | | | | | | | | |
| Cedar Springs Wind | 692,182 | 561,346 | 1,060,660 | 1,026,445 | 1,060,660 | 1,026,445 | 1,060,660 | 1,060,660 | 1,026,445 | 1,060,660 | 1,026,445 | 1,060,660 | 11,723,272 |
| Cedar Springs Wind III | 525,964 | 426,547 | 805,958 | 779,959 | 805,958 | 779,959 | 805,958 | 805,958 | 779,959 | 805,958 | 779,959 | 805,958 | 8,908,094 |
| Combine Hills Wind | 382,040 | 462,911 | 563,228 | 559,423 | 477,324 | 411,902 | 459,242 | 391,371 | 365,453 | 382,799 | 466,477 | 581,128 | 5,503,297 |
| Cove Mountain Solar | 184,583 | 193,926 | 338,034 | 367,992 | 423,558 | 455,521 | 441,868 | 418,099 | 358,534 | 288,620 | 207,377 | 170,493 | 3,848,605 |
| Cove Mountain Solar II | 458,099 | 481,286 | 838,933 | 913,283 | 1,051,186 | 1,130,512 | 1,096,629 | 1,037,639 | 889,810 | 716,297 | 511,782 | 420,758 | 9,546,214 |
| Deseret Purchase | 2,840,098 | 2,915,128 | 2,727,553 | 2,521,220 | 2,533,278 | 2,590,890 | 3,059,829 | 3,059,829 | 3,027,673 | 3,012,935 | 2,698,076 | 2,901,730 | 33,888,237 |
| Eagle Mountain - UAMPS/UMPA | 176,341 | 157,638 | 141,030 | - | - | - | - | - | - | - | - | - | 475,008 |
| Gemstate | 143,152 | 143,152 | 143,152 | 143,152 | 143,152 | 143,152 | 143,152 | 143,152 | 143,152 | 143,152 | 143,152 | 143,152 | 1,717,824 |
| Graphite Solar | 315,660 | 357,582 | 564,720 | 619,746 | 695,093 | 713,256 | 695,674 | 650,775 | 583,233 | 486,297 | 359,441 | 268,882 | 6,310,359 |
| Horseshoe Solar | - | - | - | - | - | - | 649,761 | 615,683 | 512,127 | 411,472 | 254,320 | 201,944 | 2,645,307 |
| Hunter Solar | 373,043 | 422,907 | 644,277 | 672,412 | 766,749 | 793,441 | 754,302 | 709,070 | 661,156 | 564,215 | 400,171 | 325,021 | 7,086,765 |
| Hurricane Purchase | 14,960 | 14,960 | 14,960 | 14,960 | 14,960 | 14,960 | 14,960 | 14,960 | 14,960 | 14,960 | 14,960 | 14,960 | 179,516 |
| MagCorp Reserves | 372,930 | 368,920 | 372,930 | 376,940 | 376,940 | 376,940 | 372,930 | 372,930 | 344,860 | 364,910 | 372,930 | 364,910 | 4,439,070 |
| Milican Solar | 90,121 | 137,530 | 210,849 | 265,395 | 314,995 | 342,866 | 386,117 | 341,184 | 274,582 | 179,792 | 115,156 | 79,022 | 2,737,608 |
| Milford Solar | 355,955 | 409,907 | 604,638 | 672,546 | 790,680 | 833,649 | 742,399 | 714,697 | 666,681 | 537,668 | 391,173 | 308,226 | 7,028,220 |
| Monsanto Reserves | 1,666,667 | 1,666,667 | 1,666,667 | 1,666,667 | 1,666,667 | 1,666,667 | 1,666,667 | 1,666,667 | 1,666,667 | 1,666,667 | 1,666,667 | 1,666,667 | 20,000,000 |
| Nucor | 594,150 | 594,150 | 594,150 | 594,150 | 594,150 | 594,150 | 594,150 | 594,150 | 594,150 | 594,150 | 594,150 | 594,150 | 7,129,800 |
| Old Mill Solar | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Pavant III Solar | - | - | - | - | - | - | - | - | - | - | - | - | - |
| PGE Cove | 12,899 | 12,899 | 12,899 | 12,899 | 12,899 | 12,899 | 12,899 | 12,899 | 12,899 | 12,899 | 12,899 | 12,899 | 154,785 |
| Prineville Solar | 61,904 | 94,469 | 140,083 | 176,321 | 209,274 | 227,791 | 256,526 | 226,673 | 182,425 | 119,449 | 76,506 | 52,500 | 1,823,922 |
| Rock River Wind | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Rocket Solar | - | - | - | - | - | - | - | - | - | 13,491 | 255,513 | 211,145 | 480,149 |
| Sigurd Solar | 311,118 | 347,365 | 512,316 | 559,359 | 642,898 | 706,593 | 656,935 | 602,207 | 562,226 | 456,223 | 320,617 | 269,324 | 5,947,182 |
| Small Purchases east | 1,173 | 1,213 | 1,172 | 1,172 | 1,233 | 1,203 | 1,226 | 1,202 | 1,153 | 1,157 | 1,209 | 1,176 | 14,288 |
| Small Purchases west | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Soda Lake Geothermal | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Three Buttes Wind | 2,790,662 | 1,806,920 | 2,141,628 | 1,609,251 | 1,428,678 | 1,205,304 | 804,843 | 950,802 | 1,185,464 | 1,741,196 | 2,346,698 | 2,701,069 | 20,712,516 |
| Top of the World Wind | 5,436,528 | 3,612,747 | 4,245,733 | 3,266,227 | 2,910,525 | 2,398,843 | 1,719,857 | 1,873,298 | 2,296,246 | 3,519,349 | 4,486,125 | 4,898,057 | 40,663,534 |
| Tri-State Purchase | - | - | - | - | - | - | - | - | - | - | - | - | - |
| UT Solar Adjustment | (541,029) | (605,122) | (1,169,630) | (1,299,093) | (1,513,549) | (1,550,024) | (2,149,849) | (2,011,881) | (1,693,248) | (1,394,180) | (1,147,788) | (869,353) | (15,944,747) |
| Wolverine Creek Wind | 769,735 | 899,379 | 1,146,015 | 1,054,117 | 799,585 | 851,108 | 677,648 | 647,369 | 760,687 | 840,892 | 971,473 | 970,371 | 10,388,378 |
| Long Term Firm Purchases Total | $ 18,028,933 | $ 15,484,424 | $ 18,321,953 | $ 16,574,542 | $ 16,206,893 | $ 15,728,025 | $ 14,924,382 | $ 14,899,393 | $ 15,217,295 | $ 16,541,026 | $ 17,325,488 | $ 18,154,849 | $ 197,407,203 |

**California ECAC 2022 Projected Net Power Cost** — **Exhibit PAC/104**

| | Jan-22 | Feb-22 | Mar-22 | Apr-22 | May-22 | Jun-22 | Jul-22 | Aug-22 | Sep-22 | Oct-22 | Nov-22 | Dec-22 | Total 2022 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Qualifying Facilities | | | | | | | | | | | | | |
| QF California | $ 162,633 | $ 172,651 | $ 205,751 | $ 212,594 | $ 193,211 | $ 159,233 | $ 134,854 | $ 130,374 | $ 123,448 | $ 127,844 | $ 126,171 | $ 146,640 | $ 1,895,406 |
| QF Idaho | 522,317 | 485,716 | 524,279 | 455,588 | 489,276 | 616,519 | 646,699 | 575,846 | 527,267 | 553,523 | 526,156 | 613,053 | 6,536,240 |
| QF Oregon | 2,767,508 | 2,985,364 | 3,999,426 | 5,027,644 | 5,387,968 | 5,691,881 | 5,580,713 | 5,334,306 | 4,531,951 | 3,459,567 | 2,367,692 | 2,265,849 | 49,399,870 |
| QF Utah | 848,618 | 885,366 | 1,056,273 | 1,100,403 | 1,208,104 | 1,228,948 | 1,145,332 | 1,137,818 | 1,069,438 | 1,017,171 | 896,403 | 815,062 | 12,408,936 |
| QF Washington | - | - | - | 5,769 | 20,936 | 50,654 | 56,972 | 52,342 | 25,045 | 2,284 | - | - | 214,001 |
| QF Wyoming | 10,075 | 8,452 | 10,106 | 6,275 | 5,030 | 3,054 | 8,330 | 7,517 | 4,210 | 5,954 | 6,819 | 10,449 | 86,270 |
| Biomass One QF | 1,267,643 | 1,228,418 | 1,357,354 | 1,474,648 | 963,426 | 476,188 | 1,470,267 | 1,457,176 | 1,399,895 | 1,498,754 | 1,431,020 | 829,096 | 14,853,885 |
| DCFP QF | 4,070 | 4,892 | 3,892 | 2,838 | 2,994 | 5,684 | 21,446 | 30,755 | 28,479 | 10,800 | 5,245 | 5,055 | 126,149 |
| Enterprise Solar I QF | 614,859 | 748,994 | 974,310 | 1,107,272 | 1,245,638 | 1,373,505 | 1,524,913 | 1,501,220 | 1,172,076 | 949,208 | 700,536 | 541,066 | 12,453,598 |
| Escalante 1 Solar QF | 562,807 | 675,596 | 877,224 | 1,006,684 | 1,179,056 | 1,296,956 | 1,406,566 | 1,385,489 | 1,086,234 | 867,742 | 639,811 | 504,107 | 11,488,271 |
| Escalante 2 Solar QF | 528,800 | 634,303 | 826,459 | 946,736 | 1,115,939 | 1,226,322 | 1,329,310 | 1,299,965 | 1,023,737 | 813,742 | 598,232 | 469,523 | 10,813,068 |
| Escalante 3 Solar QF | 515,134 | 620,061 | 802,066 | 921,520 | 1,088,676 | 1,197,100 | 1,293,956 | 1,264,776 | 995,093 | 744,863 | 548,273 | 431,094 | 10,422,610 |
| ExxonMobil QF | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Five Pine Wind QF | 533,030 | 876,180 | 791,676 | 830,464 | 507,541 | 559,614 | 664,263 | 614,829 | 777,853 | 769,372 | 905,957 | 907,876 | 8,738,655 |
| Granite Mountain East Solar QF | 546,621 | 611,857 | 890,164 | 982,955 | 1,148,321 | 1,250,346 | 1,322,763 | 1,258,482 | 971,017 | 804,688 | 577,589 | 463,868 | 10,828,670 |
| Granite Mountain West Solar QF | 361,832 | 405,541 | 590,326 | 651,030 | 760,411 | 827,011 | 874,938 | 831,680 | 642,114 | 531,914 | 381,550 | 306,628 | 7,164,975 |
| Iron Springs QF | 632,002 | 658,831 | 891,849 | 1,009,544 | 1,120,621 | 1,275,729 | 1,327,770 | 1,315,306 | 997,925 | 810,834 | 574,379 | 495,857 | 11,110,648 |
| Latigo Wind QF | 1,001,227 | 919,869 | 1,128,019 | 887,991 | 857,816 | 756,256 | 653,785 | 563,309 | 626,185 | 797,001 | 715,569 | 745,340 | 9,652,364 |
| Mountain Wind 1 QF | 1,397,906 | 1,038,926 | 881,867 | 687,035 | 478,109 | 504,295 | 417,864 | 425,509 | 469,765 | 681,945 | 912,095 | 1,078,321 | 8,973,637 |
| Mountain Wind 2 QF | 2,038,828 | 1,557,980 | 1,360,788 | 1,070,765 | 748,092 | 910,931 | 781,932 | 700,590 | 777,806 | 1,020,860 | 1,413,964 | 1,602,980 | 13,985,518 |
| North Point Wind QF | 1,119,374 | 1,887,863 | 1,762,544 | 1,863,861 | 1,131,008 | 1,268,824 | 1,538,820 | 1,523,257 | 1,848,717 | 1,787,346 | 1,924,728 | 1,878,455 | 19,534,795 |
| Oregon Wind Farm QF | 721,493 | 964,976 | 1,121,079 | 1,303,960 | 1,245,235 | 1,245,980 | 1,240,389 | 1,116,721 | 925,235 | 731,668 | 795,437 | 1,020,460 | 12,432,632 |
| Pavant II Solar QF | 201,314 | 255,660 | 379,339 | 434,447 | 514,699 | 570,761 | 649,719 | 654,766 | 487,627 | 364,198 | 240,997 | 196,180 | 4,949,705 |
| Pioneer Wind 1 QF | 1,307,719 | 925,080 | 1,302,648 | 1,021,708 | 676,800 | 737,081 | 856,229 | 825,193 | 541,890 | 866,588 | 1,349,151 | 1,085,602 | 11,495,689 |
| Power County North Wind QF | 431,502 | 570,443 | 549,212 | 536,482 | 373,560 | 365,543 | 386,891 | 379,427 | 392,483 | 533,545 | 543,645 | 627,035 | 5,689,769 |
| Power County South Wind QF | 381,111 | 502,335 | 496,004 | 498,085 | 323,108 | 325,843 | 342,613 | 353,598 | 347,429 | 467,178 | 490,511 | 543,731 | 5,071,546 |
| Roseburg Dillard QF | 44,544 | 51,457 | 27,164 | 104,964 | 107,166 | 90,090 | 245,085 | 171,264 | 73,254 | 75,375 | 76,026 | 64,172 | 1,130,561 |
| Sage I Solar QF | 80,192 | 79,413 | 189,005 | 204,759 | 233,577 | 261,123 | 333,738 | 333,817 | 207,287 | 154,769 | 104,237 | 74,940 | 2,256,858 |
| Sage II Solar QF | 80,277 | 79,507 | 189,206 | 204,979 | 233,789 | 261,418 | 334,094 | 334,188 | 207,523 | 154,927 | 104,366 | 75,010 | 2,259,284 |
| Sage III Solar QF | 67,598 | 66,161 | 156,107 | 166,890 | 191,458 | 213,576 | 272,357 | 272,200 | 171,079 | 129,834 | 88,345 | 63,665 | 1,859,270 |
| Spanish Fork Wind 2 QF | 222,450 | 179,011 | 207,228 | 163,645 | 154,892 | 217,017 | 287,456 | 318,786 | 275,436 | 245,056 | 255,132 | 261,068 | 2,787,179 |
| Sunnyside QF | 2,381,788 | 2,222,745 | 2,546,914 | 2,217,306 | 2,795,181 | 2,803,574 | 3,015,993 | 3,003,249 | 2,782,074 | 2,472,647 | 2,766,511 | 2,567,891 | 31,575,874 |
| Sweetwater Solar QF | 257,166 | 371,747 | 562,484 | 683,975 | 807,848 | 977,679 | 1,106,980 | 1,036,167 | 809,399 | 623,027 | 297,691 | 200,503 | 7,734,666 |
| Tesoro QF | 55,044 | 40,823 | 32,699 | 22,874 | 32,507 | 8,826 | 12,237 | 21,352 | 10,912 | 9,331 | 12,344 | 56,885 | 315,834 |
| Three Peaks Solar QF | 412,887 | 472,797 | 625,440 | 830,253 | 853,852 | 908,370 | 1,029,086 | 1,000,023 | 790,900 | 669,141 | 442,886 | 370,096 | 8,405,732 |
| Threemile Canyon Wind QF | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Utah Pavant Solar QF | 241,761 | 277,105 | 474,572 | 555,307 | 656,455 | 732,080 | 849,723 | 809,453 | 675,540 | 507,862 | 322,448 | 266,427 | 6,368,732 |
| Utah Red Hills Solar QF | 484,702 | 615,593 | 784,787 | 1,023,184 | 1,185,775 | 1,224,261 | 1,478,356 | 1,442,811 | 1,301,276 | 803,875 | 586,211 | 461,634 | 11,392,463 |
| Qualifying Facilities Total | $ 22,806,832 | $ 24,081,715 | $ 28,578,260 | $ 30,224,434 | $ 30,038,075 | $ 31,622,272 | $ 34,642,439 | $ 33,483,558 | $ 29,097,599 | $ 26,064,433 | $ 23,728,127 | $ 22,045,618 | $ 336,413,361 |
| Mid-Columbia Contracts | | | | | | | | | | | | | |
| Grant - Priest Rapids | $ 184,760 | $ 184,760 | $ 184,760 | $ 184,760 | $ 184,760 | $ 184,760 | $ 184,760 | $ 184,760 | $ 184,760 | $ 184,760 | $ 184,760 | $ 184,760 | $ 2,217,125 |
| Grant Reasonable | (79,720) | (79,720) | (79,720) | (79,720) | (79,720) | (79,720) | (79,720) | (79,720) | (79,720) | (79,720) | (79,720) | (79,720) | (956,639) |
| Grant Surplus | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Mid-Columbia Contracts Total | $ 105,040 | $ 105,040 | $ 105,040 | $ 105,040 | $ 105,040 | $ 105,040 | $ 105,040 | $ 105,040 | $ 105,040 | $ 105,040 | $ 105,040 | $ 105,040 | $ 1,260,486 |
| Total Long Term Firm Purchases | $ 40,940,806 | $ 39,671,179 | $ 47,005,253 | $ 46,904,016 | $ 46,350,008 | $ 47,455,337 | $ 49,671,861 | $ 48,487,991 | $ 44,419,934 | $ 42,710,499 | $ 41,158,656 | $ 40,305,508 | $ 535,081,050 |
| Storage & Exchange | | | | | | | | | | | | | |
| APS Exchange | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Cowlitz Swift | - | - | - | - | - | - | - | - | - | - | - | - | - |
| PSCo Exchange | 450,000 | 450,000 | 450,000 | 450,000 | 450,000 | 450,000 | 450,000 | 450,000 | 450,000 | 450,000 | - | - | 4,500,000 |
| SCL State Line | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Total Storage & Exchange | $ 450,000 | $ 450,000 | $ 450,000 | $ 450,000 | $ 450,000 | $ 450,000 | $ 450,000 | $ 450,000 | $ 450,000 | $ 450,000 | $ - | $ - | $ 4,500,000 |
| Total Short Term Firm Purchases | $ 14,207,168 | $ 11,297,536 | $ 15,244,811 | $ 1,475,235 | $ 11,367,923 | $ 18,258,063 | $ 40,294,181 | $ 40,527,382 | $ 20,075,416 | $ 11,110,339 | $ 10,435,965 | $ 17,472,291 | $ 211,766,311 |
| Total Secondary Purchases | | | | | | | | | | | | | - |
| **Total Purchased Power & Net Interchange** | $ 55,597,974 | $ 51,418,716 | $ 62,700,064 | $ 48,829,251 | $ 58,167,932 | $ 66,163,400 | $ 90,416,042 | $ 89,465,374 | $ 64,945,351 | $ 54,270,839 | $ 51,594,620 | $ 57,777,799 | $ 751,347,361 |
| **Wheeling & U. of F. Expense** | | | | | | | | | | | | | |
| Firm Wheeling | $ 13,473,441 | $ 13,255,570 | $ 13,526,678 | $ 13,310,416 | $ 12,006,585 | $ 12,843,394 | $ 13,470,943 | $ 13,547,418 | $ 12,562,964 | $ 13,005,692 | $ 12,789,218 | $ 13,456,061 | $ 157,248,382 |
| Non-Firm Wheeling | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Total Wheeling & U. of F. Expense** | $ 13,473,441 | $ 13,255,570 | $ 13,526,678 | $ 13,310,416 | $ 12,006,585 | $ 12,843,394 | $ 13,470,943 | $ 13,547,418 | $ 12,562,964 | $ 13,005,692 | $ 12,789,218 | $ 13,456,061 | $ 157,248,382 |

| | Jan-22 | Feb-22 | Mar-22 | Apr-22 | May-22 | Jun-22 | Jul-22 | Aug-22 | Sep-22 | Oct-22 | Nov-22 | Dec-22 | Total 2022 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|

**California ECAC 2022 Projected Net Power Cost** **Exhibit PAC/104**

| | Jan-22 | Feb-22 | Mar-22 | Apr-22 | May-22 | Jun-22 | Jul-22 | Aug-22 | Sep-22 | Oct-22 | Nov-22 | Dec-22 | Total 2022 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Coal Fuel Burn Expense** | | | | | | | | | | | | | |
| Cholla | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Colstrip | 1,924,390 | 1,737,016 | 1,898,331 | 1,745,153 | 1,256,369 | 1,270,072 | 1,450,999 | 1,585,851 | 1,418,210 | 909,088 | 1,000,147 | 1,325,256 | 17,520,880 |
| Craig | 1,972,429 | 1,681,651 | 1,791,507 | 1,426,816 | 787,302 | 946,517 | 1,211,393 | 1,708,632 | 1,680,151 | 1,510,473 | 951,764 | 954,090 | 16,622,724 |
| Dave Johnston | 6,244,227 | 5,800,913 | 5,313,272 | 5,925,294 | 4,957,026 | 3,445,268 | 3,543,208 | 4,341,367 | 3,973,537 | 4,115,342 | 3,516,487 | 4,177,866 | 55,353,808 |
| Hayden | 1,146,680 | 982,155 | 1,018,610 | 891,926 | 1,186,879 | 1,216,940 | 1,197,792 | 1,014,662 | 734,955 | 1,054,744 | 897,664 | 840,460 | 12,183,468 |
| Hunter | 14,242,390 | 11,604,768 | 10,818,857 | 4,956,263 | 7,651,749 | 7,783,418 | 9,900,506 | 10,134,903 | 10,053,593 | 9,874,554 | 10,775,437 | 10,916,671 | 118,713,109 |
| Huntington | 12,464,096 | 9,832,927 | 9,396,515 | 6,169,200 | 5,006,439 | 7,028,722 | 9,928,233 | 9,608,512 | 8,201,702 | 7,531,738 | 8,617,774 | 10,718,723 | 104,504,580 |
| Jim Bridger | 12,782,905 | 13,790,009 | 12,829,590 | 11,034,165 | 11,481,792 | 15,665,919 | 21,327,116 | 21,244,615 | 18,003,961 | 18,310,193 | 17,985,605 | 18,160,501 | 192,616,372 |
| Naughton | 3,045,518 | 2,284,803 | 2,237,301 | 1,604,055 | 1,426,768 | 1,716,995 | 2,977,599 | 2,909,323 | 2,624,272 | 2,490,899 | 2,278,064 | 2,698,147 | 28,293,745 |
| Wyodak | 2,397,595 | 2,386,654 | 2,559,800 | 2,536,406 | 2,674,092 | 1,971,847 | 2,525,610 | 2,445,262 | 2,230,813 | 2,196,131 | 1,532,725 | 1,245,325 | 26,702,259 |
| **Total Coal Fuel Burn Expense** | $ 56,220,230 | $ 50,100,897 | $ 47,863,782 | $ 36,289,277 | $ 36,428,416 | $ 41,045,699 | $ 54,062,455 | $ 54,993,127 | $ 48,921,193 | $ 47,993,161 | $ 47,555,668 | $ 51,037,040 | $ 572,510,944 |
| **Gas Fuel Burn Expense** | | | | | | | | | | | | | |
| Chehalis | $ 7,359,642 | $ 3,071,017 | $ 1,101,710 | $ 5,194,097 | $ 3,104,944 | $ 2,546,232 | $ 4,771,113 | $ 4,410,756 | $ 4,690,778 | $ 5,910,531 | $ 4,939,573 | $ 5,511,283 | $ 52,611,675 |
| Currant Creek | 6,157,677 | 6,566,264 | 1,015,992 | 4,113,328 | 3,734,811 | 5,150,549 | 6,328,128 | 4,466,604 | 4,254,643 | 5,107,662 | 6,643,809 | 4,823,419 | 58,362,884 |
| Gadsby | 585,035 | 428,919 | 289,139 | 226,962 | 267,842 | 580,086 | 1,031,781 | 1,205,189 | 972,013 | 651,814 | 639,440 | 1,127,529 | 8,005,750 |
| Gadsby CT | 356,442 | 154,349 | 56,442 | 61,267 | 57,145 | 392,515 | 767,272 | 784,064 | 656,618 | 627,937 | 521,091 | 931,665 | 5,366,805 |
| Hermiston | 4,113,470 | 3,166,919 | 3,216,589 | 2,022,663 | 1,170,034 | 636,465 | 2,368,690 | 2,097,008 | 2,269,290 | 1,621,185 | 1,959,535 | 2,411,073 | 27,052,921 |
| Lake Side 1 | 6,211,054 | 4,970,208 | 6,815,801 | 5,913,363 | 3,909,059 | 4,159,110 | 6,929,215 | 7,004,352 | 6,013,533 | 6,260,860 | 6,186,220 | 5,295,775 | 69,668,552 |
| Lake Side 2 | 4,388,985 | 2,678,923 | 1,460,995 | 1,114,459 | 2,053,428 | 3,444,266 | 4,179,974 | 4,333,825 | 3,930,813 | 4,326,560 | 4,289,185 | 5,419,826 | 41,621,239 |
| Naughton - Gas | 886,268 | 780,359 | 243,996 | 282,817 | 590,074 | 916,175 | 2,192,451 | 2,140,542 | 1,325,374 | 1,556,842 | 1,104,889 | 2,744,006 | 14,763,793 |
| **Total Gas Fuel Burn Expense** | $ 30,058,572 | $ 21,816,958 | $ 14,200,664 | $ 18,928,956 | $ 14,887,337 | $ 17,825,397 | $ 28,568,623 | $ 26,442,340 | $ 24,113,062 | $ 26,063,392 | $ 26,283,742 | $ 28,264,575 | $ 277,453,618 |
| **Other Generation** | | | | | | | | | | | | | |
| Black Cap Solar | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Blundell | 666,076 | 601,617 | 601,617 | 603,311 | 614,861 | 579,403 | 554,672 | 576,700 | 589,628 | 585,218 | 338,058 | 374,256 | 6,685,418 |
| **Total Other Generation** | $ 666,076 | $ 601,617 | $ 601,617 | $ 603,311 | $ 614,861 | $ 579,403 | $ 554,672 | $ 576,700 | $ 589,628 | $ 585,218 | $ 338,058 | $ 374,256 | $ 6,685,418 |
| **Net Power Cost** | $ 120,757,460 | $ 115,484,935 | $ 112,721,712 | $ 102,571,919 | $ 107,184,318 | $ 117,102,895 | $ 155,135,510 | $ 147,588,923 | $ 117,226,638 | $ 115,822,856 | $ 117,122,942 | $ 132,235,958 | $ 1,460,956,065 |

Application No. 21-08-_____
Exhibit No. PAC/105
Witness: Douglas R. Staples

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP 2022 ECAC

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2022 California-allocated Net Power Costs

August 2, 2021

**Exhibit PAC/105**
**PacifiCorp**
**August 2, 2021**
**California ECAC 2022 Projected Net Power Cost**

| Description | CY 2022 Total Company | Per Docket A.18-04-002 2017 Protocol Factor | California Factor % | CY 2022 California Allocated |
|---|---|---|---|---|
| Sales for Resale (Account 447) | | | | |
| Existing Firm Sales PPL | 7,750,540 | SG | 1.580% | 122,492 |
| Existing Firm Sales UPL | - | SG | 1.580% | - |
| Post-merger Firm Sales | 296,539,117 | SG | 1.580% | 4,686,606 |
| Total Revenue | 304,289,657 | | | **4,809,099** |
| | - | | | |
| Purchased Power (Account 555) | | | | |
| Existing Firm Demand PPL | 8,474,963 | SG | 1.580% | 133,941 |
| Existing Firm Demand UPL | 13,322,012 | SG | 1.580% | 210,546 |
| Existing Firm Energy | 47,739,069 | SE | 1.490% | 711,444 |
| Post-merger Firm | 681,811,317 | SG | 1.580% | 10,775,581 |
| Other Generation | - | SG | 1.580% | - |
| Seasonal Contracts | - | SG | 1.580% | - |
| Total Purchased Power | 751,347,361 | | | **11,831,512** |
| | - | | | |
| Wheeling (Account 565) | | | | |
| Existing Firm PPL | 23,949,309 | SG | 1.580% | 378,503 |
| Existing Firm UPL | - | SG | 1.580% | - |
| Post-merger Firm | 116,755,331 | SG | 1.580% | 1,845,241 |
| Non-firm | 16,543,742 | SE | 1.490% | 246,547 |
| Total Wheeling Expense | 157,248,382 | | | **2,470,292** |
| | - | | | |
| Fuel Expense (Accounts 501, 503 and 547) | | | | |
| Fuel Consumed - Coal | 572,510,944 | SE | 1.490% | 8,531,995 |
| Fuel Consumed - Gas | 6,987,003 | SE | 1.490% | 104,126 |
| Steam From Other Sources | 6,685,418 | SE | 1.490% | 99,631 |
| Natural Gas Consumed | 265,844,796 | SE | 1.490% | 3,961,822 |
| Simple Cycle Combustion Turbines | 4,621,819 | SE | 1.490% | 68,878 |
| Cholla/APS Exchange | - | SE | 1.490% | - |
| Total Fuel Expense | 856,649,980 | | | **12,766,452** |
| | - | | | |
| **CY 2022 Net Power Cost** | **1,460,956,065** | | | **22,259,157** |

Application No. 21-08-_____
Exhibit No. PAC/106
Witness: Douglas R. Staples

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP 2022 ECAC

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ARB Administrative Costs

CONFIDENTIAL

August 2, 2021

**CONFIDENTIAL Exhibit PAC/106**
**PacifiCorp**
**August 2, 2021**
**California Air Resources Boards**
**Administrative Costs[1]**

**CONFIDENTIAL INFORMATION IS SHADED**

| | 2020 Forecast | 2020 Actual | 2021 Forecast | 2021 Forecast/Actual | 2022 Forecast |
|---|---|---|---|---|---|
| CARB Implementation Fees | [redacted] | | [redacted] | | [redacted] |
| Mandatory Reporting Verification Costs | | | | | |
| Total Administrative Costs[1] | $ 47,845 | $ 58,897 | $ 82,419 | $ 93,695 | $ 46,189 |

[1] Excludes etimated emission obligation cost from the purchase of allowances and forecast revenue from the sale of directly allocated allowances. On August 1, 2013 PacifiCorp filed a separate application forecasting the costs from the purchase of allowances and revenue from the sale of allowances.

Application No. 21-08-_____
Exhibit No. PAC/200 - 209
Witness: Mary M. Wiencke

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP 2022 ECAC

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Direct Testimony of Mary M. Wiencke

PUBLIC VERSION

August 2, 2021

# Table of Contents



**Attached Exhibits**

## I. Witness Qualifications

**Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or Company).**

A. My name is Mary M. Wiencke. My business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. I am employed by PacifiCorp as Vice President of Market, Regulation, and Transmission Policy.

**Q. Please describe your education and business experience.**

A. I have a Bachelor of Arts degree in Environmental Science from Barnard College and a J.D. from Lewis & Clark Law School. I have been employed by PacifiCorp for 13 years in various positions of responsibility in both legal and policy roles.

**Q. Please explain your responsibilities as PacifiCorp's Vice President of Market, Regulation, and Transmission Policy.**

A. My current responsibilities include developing PacifiCorp's environmental policy, strategy, and programs as well as ensuring compliance for Company-wide renewable portfolio standards (RPS), reporting of greenhouse gas (GHG) emissions for California, Oregon, and Washington, and overseeing environmental commodity transactions. Most relevant to this application, I manage PacifiCorp's compliance with the California Air Resources Board (ARB) Mandatory Reporting Regulation and Cap and Trade Program.

## II. Summary of Testimony

**Q. Please summarize your direct testimony.**

A. My direct testimony: (1) reconciles PacifiCorp's forecast GHG allowance costs and revenues set out in the Company's 2021 Energy Cost Adjustment Clause (ECAC) and

GHG Application (A.20-08-002) (2021 Application) with actual GHG allowance costs and revenues through May 31, 2021; and (2) forecasts PacifiCorp's GHG allowance costs and revenues for the remainder of 2021 and 2022. PacifiCorp's forecast of 2021 GHG allowance costs and revenues will be reconciled next year in the 2023 ECAC and GHG Application. The 2023 Application will also include a final reconciliation of 2020 GHG allowance costs based on ARB's 2020 verified emissions data report.[1]

**Q. Please describe the exhibits provided in support of your direct testimony.**

A. I prepared nine exhibits in support of my direct testimony.

- Confidential Exhibit PAC/201 – California Public Utilities Commission (Commission) Template C Weighted Average Cost of Compliance Instruments. This exhibit provides the Company's monthly accrued compliance obligation based on the weighted average cost methodology prescribed by the Commission. This template was developed by the Commission and modified in (D) 19-04-016 on April 25, 2020. *See* Decisions (D.) 14-10-033, D.14-10-055, D.15-01-024, and D.15-04-016.

- Confidential Exhibit PAC/202 – Commission Template D-2 Annual GHG Emissions and Associated Compliance Obligation. This exhibit provides annual forecast and actual compliance obligation by year in metric tons carbon dioxide equivalent (MTCO2e) and dollars. This template was developed by the Commission. *See* D.14-10-033, D.14-10-055, and D.15-01-024.

- Confidential Exhibit PAC/203 – Summary of the GHG Allowance Costs Sub-Balancing Account. This exhibit provides a reconciliation of the balance in the GHG Allowance Costs Sub-Balancing Account and shows whether there is an over-collection or under-collection from customers that is included in the calculation of the GHG allowance costs recovered from customers.

- Confidential Exhibit PAC/204 – 2022 Forecast Compliance Obligation and GHG Allowance Costs. This exhibit calculates the Company's 2022 forecasted monthly GHG compliance cost based on a proxy price.

[1] ARB is expected to issue its 2020 Verified Emissions Report by August 15, 2021.

- Confidential Exhibit PAC/205 – 2020 Recorded GHG Allowance Revenue. This exhibit summarizes the GHG allowances sold in 2020 at the ARB quarterly auctions.

- Confidential Exhibit PAC/206 – 2021 Recorded/Forecast GHG Allowance Revenue. This exhibit summarizes the GHG allowances sold at the ARB quarterly auctions through May 31, 2021 and the amount (if any) forecast to be sold during the remainder of the year.

- Confidential Exhibit PAC/207 – Summary of the GHG Allowance Revenue Balancing Account. This exhibit provides a reconciliation of the balance in the GHG Allowance Revenue Balancing Account and shows the remaining balance to be returned to customers in 2021.

- Confidential Exhibit PAC/208 – 2022 Forecast GHG Allowance Revenue. This exhibit calculates the Company's 2022 forecast GHG allowance revenue from the ARB quarterly auctions based on a proxy price.

- Confidential Exhibit PAC/209 – Commission Template D-5 History and Forecast of Revenue, Costs, and Emissions Intensity. This exhibit summarizes the forecast and recorded GHG allowance costs and revenues over the program years. This template was developed by the Commission. *See* D.14-10-033, D.14-10-055, and D.15-01-024.

## III. Forecast and Actual 2019 and 2020 GHG Allowance Costs

**Q. Please describe the types of GHG compliance costs PacifiCorp has incurred and is forecasted to incur.**

A. PacifiCorp is subject to regulation as a first jurisdictional deliverer of electricity into California under ARB's GHG cap-and-trade program. As a first jurisdictional deliverer, PacifiCorp must surrender to ARB one GHG compliance instrument (i.e., a GHG allowance or offset credit) for each metric ton of carbon dioxide emitted or its equivalent. At this time, PacifiCorp only has direct GHG costs (i.e., the costs associated with procuring GHG allowances). PacifiCorp has not incurred, and does not expect to incur, any indirect GHG costs (e.g., the embedded GHG compliance costs associated with electricity procured in the wholesale market) as part of its retail compliance obligation.

**Q. What were PacifiCorp's actual final GHG allowance costs for 2019?**

A. On November 4, 2020, ARB issued its 2019 Verified Emissions Report. Based on PacifiCorp's 2019 Verified Emissions Report, the actual final cost of PacifiCorp's GHG compliance obligation for 2019 is [Begin Confidential] [redacted] [End Confidential].[2] The Company's 2019 actual retail compliance obligation was [Begin Confidential] [redacted] [End Confidential] allowances. *See* Confidential Exhibits PAC/201 and PAC/202. The actual final cost for 2019 is included in the reconciliation of the balance in the GHG Allowance Costs Sub-Balancing Account as shown in Confidential Exhibit PAC/203.

**Q. What were PacifiCorp's forecast and actual GHG allowance costs for 2020?**

A. In its 2021 GHG Application, PacifiCorp forecasted that it would incur [Begin Confidential] [redacted] [End Confidential] for 2020 GHG allowance costs. *See* Confidential Exhibit PAC/202 in the Company's 2021 Application, and Confidential Exhibit PAC/202 in this application. As of May 31, 2021, PacifiCorp has accrued [Begin Confidential] [redacted] [End Confidential] for 2020 GHG allowance costs in the GHG Allowance Costs Sub-Balancing Account. There will be a final true-up to the verified 2020 GHG allowance costs in the Company's next application filed on August 1, 2022 based on the 2020 Verified Emissions Report.

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[2] All references to GHG allowance costs are based on the weighted average cost methodology prescribed by the Commission and calculated as shown in Confidential Exhibit PAC/201.

 

## IV. Forecast 2021 and 2022 GHG Allowance Costs

**Q. What did PacifiCorp forecast for 2021 GHG allowance costs in its 2021 Application?**

A. In its 2021 Application, PacifiCorp forecasted the Company would incur [Begin Confidential] [redacted] [End Confidential] for GHG Allowance Costs in 2021. *See* Confidential Exhibits PAC/202 and PAC/204 in the Company's 2021 Application and Confidential Exhibit PAC/202 in this application.

**Q. Has PacifiCorp updated its forecast for 2021 GHG allowance costs in its this Application?**

A. Yes. Through May 31, 2021, PacifiCorp has accrued [Begin Confidential] [redacted] [End Confidential] for its 2021 compliance obligation in the GHG Allowance Costs Sub-Balancing Account. PacifiCorp forecasts that it will incur additional GHG allowance costs of [Begin Confidential] [redacted] [End Confidential] from June 1, 2021, through the remainder of the year, December 31, 2021. Based on the amount accrued to date and the forecast for the remainder of the year, the updated forecast GHG allowance costs for 2021 are [Begin Confidential] [redacted] [End Confidential]. *See* Confidential Exhibit PAC/203 in this application.

**Q. What proxy price was used to calculate the Company's forecast compliance obligation for June 1, 2021 through December 31, 2021?**

A. The Company used the March 31, 2021 forward Intercontinental Exchange (ICE) settlement price of $18.51 as the GHG allowance proxy price to calculate the Company's forecast compliance costs for June 1, 2021 through December 31, 2021. *See* Confidential Exhibit PAC/201. The process for calculating the Company's 2021 compliance obligation is described in more detail below.

**Q. What GHG allowance costs does PacifiCorp forecast for 2022?**

A. The 2022 GHG allowance costs are forecast to be [Begin Confidential][redacted] [End Confidential]. Refer to Confidential Exhibit PAC/204 for the 2022 forecast compliance obligation and GHG allowance costs.

**Q. What methodology was used to forecast PacifiCorp's 2022 GHG allowance costs?**

A. As a multi-jurisdictional retail provider that has a GHG compliance obligation, PacifiCorp must calculate emissions as set out in California Code of Regulations, Section 95111. PacifiCorp's calculation of GHG allowance costs is consistent with D.14-10-033 issued October 16, 2014 and uses the straightforward methodology of multiplying its compliance obligation by the GHG allowance proxy price. PacifiCorp's compliance obligation was developed using data consistent with PacifiCorp's system generation mix forecast and California load forecast assumptions in PacifiCorp's 2022 ECAC included with this application. *See* the direct testimony and exhibits of Mr. Douglas R. Staples in support of the Company's ECAC provided as Exhibits PAC/100 through Confidential Exhibit PAC/106. Allowance costs for 2021 are based on the Company's accrued compliance obligation through May 31, 2021, plus the forecast compliance obligation from June 2021 through December 2021 multiplied by the GHG allowance proxy price. Allowance costs for 2022 are based on a forecast of the Company's compliance obligation for 2022 multiplied by the GHG allowance proxy price. *See* Confidential Exhibits PAC/201 and PAC/204.

**Q. How was the 2022 proxy price developed?**

A. The GHG allowance proxy price forecast of $19.36 for 2022 was developed in accordance with D.14-10-033. PacifiCorp uses a GHG allowance proxy price based on the forward ICE settlement price for GHG allowances with December delivery of the forecast year 2022, consistent with the methodology used to calculate forward prices for other commodities in its ECAC application. *See* Confidential Exhibit PAC/204 for the 2022 forecast GHG allowance costs.

**Q. Has the Company prepared an exhibit summarizing the balance in the GHG Allowance Costs Sub-Balancing Account?**

A. Yes. A summary of the balance in the GHG Allowance Costs Sub-Balancing Account is shown in Confidential Exhibit PAC/203. The summary shows a projected [Begin Confidential][redacted][End Confidential] of GHG allowance costs at the end of 2021.

**Q. Will the balance in the GHG Allowance Costs Sub-Balancing Account be considered in the calculation of the GHG allowance costs to be recovered in rates in 2022?**

A. Yes. See the testimony of Company witness Ms. Judith M. Ridenour, Exhibit PAC/600, and accompanying Exhibit PAC/602.

## V. Forecast and Actual 2020 GHG Allowance Revenue

**Q. What were PacifiCorp's forecast GHG allowance revenues for 2020?**

A. In its 2021 Application, PacifiCorp forecast $12,604,291 in GHG allowance revenues for 2020. *See* 2021 Application, Confidential Exhibit PAC/206.

**Q. What were PacifiCorp's actual GHG allowance revenues in 2020?**

A. PacifiCorp's total actual GHG allowance revenues in 2020 were $13,082,153. *See*

Confidential Exhibit PAC/205. The actual 2020 GHG allowance revenue has been included in the reconciliation of the balance in the GHG Allowance Revenue Balancing Account as shown on Confidential Exhibit PAC/207 and Confidential Exhibit PAC/605 to the direct testimony of Ms. Judith M. Ridenour.

## VI. 2021 and 2022 Forecast GHG Allowance Revenue

**Q. What are the total 2021 and 2022 forecast GHG allowance revenue?**

A. Forecast 2021 GHG allowance revenue is $10,116,732. Forecast 2022 GHG allowance revenue is $10,661,475. See Confidential Exhibits PAC/206 and PAC/208, respectively.

**Q. What methodology was used to forecast 2021 and 2022 GHG allowance revenue?**

A. PacifiCorp calculated its forecast GHG allowance revenue by multiplying its annual allowance allocation from ARB times the GHG allowance proxy price. PacifiCorp's 2021 forecast GHG allowance revenue is based on actual GHG allowance revenue received from the 2021 quarterly allowance auctions as of May 31, 2021, and the expected revenue from the sale of GHG allowances PacifiCorp expects to consign to the remaining 2021 ARB auctions, multiplied by the GHG allowance proxy price. The Company has assumed that it will submit and sell 100 percent of its 2021 allowance allocation from ARB at auctions in 2021, less allowances administratively retired by ARB to account for Energy Imbalance Market (EIM) Purchaser Emissions.[3] For calendar year 2022, the forecast is based on the expected revenue from the sale of the GHG allowances PacifiCorp expects to consign to the 2022 ARB

[3] PacifiCorp does not currently have a way to forecast EIM Purchaser Emissions; however, the amount is expected to be relatively small.

auctions multiplied by forecasted GHG allowance proxy price for 2022. *See* Confidential Exhibits PAC/206 and PAC/208.

**Q. What GHG allowance proxy price was used to determine forecast GHG allowance revenues in 2021 and 2022?**

A. The GHG allowance proxy prices for 2021 and 2022 are $18.51 and $19.36, respectively. Please refer to Section IV of my testimony for a more detailed discussion about the methodology used to develop the proxy prices for each year. The Company used the same proxy prices for determining both forecast GHG allowance costs and GHG allowance revenue in 2021 and 2022.

**Q. Did you have any concerns regarding the proxy prices used to determine the forecast GHG allowances costs and GHG allowance revenue for 2020 and 2021 in the 2021 Application A.20-08-002?**

A. Yes. In the 2021 Application, PacifiCorp used the ICE proxy price as required by D.14-10-033. However, the ICE proxy prices for 2020 and 2021 were below the 2020 and 2021 auction floor price of $16.68 and $17.71, respectively.

**Q. Were the GHG costs and revenue forecasts understated because of the proxy prices used in the 2021 Application?**

A. Yes. The GHG allowance costs were [Begin Confidential][redacted] $[redacted] [End Confidential] and revenues under stated by $2,015,253. This deviation was largely driven by the proxy price misalignment. *See* Confidential Exhibits PAC/203 and PAC/207. The understatement of revenues is solely driven by the proxy price misalignment because the number of allowances directly allocated to PacifiCorp is known in advance. For the under collection of costs, approximately $1 million is due to the difference between the forecast and actual obligation with the balance attributable to the proxy price misalignment.

**Q. Were all of PacifiCorp's consigned allowances sold in the February 2021 and May 2021 auctions?**

A. Yes.

**Q. Has the Company prepared an exhibit summarizing the balance in the GHG Allowance Revenue Balancing Account?**

A. Yes. A summary of the GHG Allowance Revenue Balancing Account is shown in Confidential Exhibit PAC/207. The summary shows a projected balance of $2,015,253 at the end of 2021 which represents less GHG allowance revenue returned to eligible customers than what was available to return to customers.

**Q. Will the balance in the GHG Allowance Revenue Balancing Account be included in the GHG allowance revenue to be distributed through the California Climate Credit in 2022?**

A. Yes. See the testimony of Company witness Ms. Judith M. Ridenour, Exhibit PAC/600, and accompanying Exhibit PAC/603.

**Q. Does this conclude your direct testimony?**

A. Yes.

Application No. 21-08-______
Exhibit No. PAC/201
Witness: Mary M. Wiencke

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP 2022 ECAC

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Commission Template C Weighted Average Cost of Compliance Instruments

CONFIDENTIAL

August 2, 2021

| Month | Transaction/Activity Details | | | | | | | | Inventory Emissions and $ | | WAC Pricing ($/MT) | Direct GHG Costs | | True-Ups | Monthly BA Entry |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Month | Transaction Date | Transaction Type | Quantity Purchased (MT) | Purchase Price ($/MT) | Total Purchase ($) | Quantity Surrendered (MT) | Surrender Price ($/MT) | Total Surrender ($) | Inventory Balance ($) | Total Qty in Inventory (MT) | WAC ($/MT) | Direct Monthly Emmissions (MT) | WAC x Direct Emmissions Qty ($) | True Up Value +/- ($) | Monthly Balancing Account Entries ($) |
| Jan-13 | [redacted] | | | | | | | | | | | | | | |
| Feb-13 | [redacted] | | | | | | | | | | | | | | |
| Mar-13 | [redacted] | | | | | | | | | | | | | | |
| Apr-13 | [redacted] | | | | | | | | | | | | | | |
| May-13 | [redacted] | | | | | | | | | | | | | | |
| Jun-13 | [redacted] | | | | | | | | | | | | | | |
| Jul-13 | [redacted] | | | | | | | | | | | | | | |
| Aug-13 | [redacted] | | | | | | | | | | | | | | |
| Sep-13 | [redacted] | | | | | | | | | | | | | | |
| Oct-13 | [redacted] | | | | | | | | | | | | | | |
| Nov-13 | [redacted] | | | | | | | | | | | | | | |
| Dec-13 | [redacted] | | | | | | | | | | | | | | |
| Jan-14 | [redacted] | | | | | | | | | | | | | | |
| Feb-14 | [redacted] | | | | | | | | | | | | | | |
| Mar-14 | [redacted] | | | | | | | | | | | | | | |
| Apr-14 | [redacted] | | | | | | | | | | | | | | |
| May-14 | [redacted] | | | | | | | | | | | | | | |
| Jun-14 | [redacted] | | | | | | | | | | | | | | |
| Jul-14 | [redacted] | | | | | | | | | | | | | | |
| Aug-14 | [redacted] | | | | | | | | | | | | | | |
| Sep-14 | [redacted] | | | | | | | | | | | | | | |
| Oct-14 | [redacted] | | | | | | | | | | | | | | |
| Nov-14 | [redacted] | | | | | | | | | | | | | | |
| Dec-14 | [redacted] | | | | | | | | | | | | | | |
| Jan-15 | [redacted] | | | | | | | | | | | | | | |
| Feb-15 | [redacted] | | | | | | | | | | | | | | |
| Mar-15 | [redacted] | | | | | | | | | | | | | | |
| Apr-15 | [redacted] | | | | | | | | | | | | | | |
| May-15 | [redacted] | | | | | | | | | | | | | | |
| Jun-15 | [redacted] | | | | | | | | | | | | | | |
| Jul-15 | [redacted] | | | | | | | | | | | | | | |
| Aug-15 | [redacted] | | | | | | | | | | | | | | |
| Sep-15 | [redacted] | | | | | | | | | | | | | | |
| Oct-15 | [redacted] | | | | | | | | | | | | | | |
| Nov-15 | [redacted] | | | | | | | | | | | | | | |
| Dec-15 | [redacted] | | | | | | | | | | | | | | |
| Jan-16 | [redacted] | | | | | | | | | | | | | | |
| Feb-16 | [redacted] | | | | | | | | | | | | | | |
| Mar-16 | [redacted] | | | | | | | | | | | | | | |
| Apr-16 | [redacted] | | | | | | | | | | | | | | |
| May-16 | [redacted] | | | | | | | | | | | | | | |
| Jun-16 | [redacted] | | | | | | | | | | | | | | |
| Jul-16 | [redacted] | | | | | | | | | | | | | | |
| Aug-16 | [redacted] | | | | | | | | | | | | | | |
| Sep-16 | [redacted] | | | | | | | | | | | | | | |
| Oct-16 | [redacted] | | | | | | | | | | | | | | |
| Nov-16 | [redacted] | | | | | | | | | | | | | | |
| Dec-16 | [redacted] | | | | | | | | | | | | | | |
| Jan-17 | [redacted] | | | | | | | | | | | | | | |
| Feb-17 | [redacted] | | | | | | | | | | | | | | |
| Mar-17 | [redacted] | | | | | | | | | | | | | | |
| Apr-17 | [redacted] | | | | | | | | | | | | | | |
| May-17 | [redacted] | | | | | | | | | | | | | | |
| Jun-17 | [redacted] | | | | | | | | | | | | | | |
| Jul-17 | [redacted] | | | | | | | | | | | | | | |
| Aug-17 | [redacted] | | | | | | | | | | | | | | |
| Sep-17 | [redacted] | | | | | | | | | | | | | | |
| Oct-17 | [redacted] | | | | | | | | | | | | | | |
| Nov-17 | [redacted] | | | | | | | | | | | | | | |
| Dec-17 | [redacted] | | | | | | | | | | | | | | |
| Jan-18 | [redacted] | | | | | | | | | | | | | | |
| Feb-18 | [redacted] | | | | | | | | | | | | | | |
| Mar-18 | [redacted] | | | | | | | | | | | | | | |
| Apr-18 | [redacted] | | | | | | | | | | | | | | |
| May-18 | [redacted] | | | | | | | | | | | | | | |
| Jun-18 | [redacted] | | | | | | | | | | | | | | |
| Jul-18 | [redacted] | | | | | | | | | | | | | | |
| Aug-18 | [redacted] | | | | | | | | | | | | | | |
| Sep-18 | [redacted] | | | | | | | | | | | | | | |
| Oct-18 | [redacted] | | | | | | | | | | | | | | |
| Nov-18 | [redacted] | | | | | | | | | | | | | | |
| Dec-18 | [redacted] | | | | | | | | | | | | | | |
| Jan-19 | [redacted] | | | | | | | | | | | | | | |
| Feb-19 | [redacted] | | | | | | | | | | | | | | |
| Mar-19 | [redacted] | | | | | | | | | | | | | | |
| Apr-19 | [redacted] | | | | | | | | | | | | | | |

| | |
|---|---|
| May-19 | [redacted] |
| Jun-19 | |
| Jul-19 | |
| Aug-19 | |
| Sep-19 | |
| Oct-19 | |
| Nov-19 | |
| Dec-19 | |
| Jan-20 | |
| Feb-20 | |
| Mar-20 | |
| Apr-20 | |
| May-20 | |
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| Jul-20 | |
| Aug-20 | |
| Sep-20 | |
| Oct-20 | |
| Nov-20 | |
| Dec-20 | |
| Jan-21 | |
| Feb-21 | |
| Mar-21 | |
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| Jul-21 | |
| Aug-21 | |
| Sep-21 | |
| Oct-21 | |
| Nov-21 | |
| Dec-21 | |

**CONFIDENTIAL INFORMATION IS SHADED**

Application No. 21-08-_____
Exhibit No. PAC/202
Witness: Mary M. Wiencke

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP 2022 ECAC

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Commission Template D-2 Annual GHG Emissions and Associated Compliance Obligation

CONFIDENTIAL

August 2, 2021

**CONFIDENTIAL**
**Exhibit PAC/202**
**PacifiCorp**
**Commission Template D-2**
**Annual GHG Emissions and Associated Compliance Obligation**
**August 2, 2021**

| | | 2013 | | 2014 | | 2015 | | 2016 | | 2017 | | 2018 | | 2019 | | 2020 | | 2021 | | 2022 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line | Description | Forecast | Recorded (Note 1) | Forecast | Recorded (Note 1) | Forecast | Recorded (Note 1) | Forecast | Recorded (Note 1) | Forecast | Recorded (Note 1) | Forecast | Recorded (Note 1) | Forecast | Recorded | Forecast | Recorded | Forecast | Recorded | Forecast | Recorded |
| 1 | **Direct GHG Emissions (MTCO2e)** | | | | | | | | | | | | | | | | | | | | |
| 2 | Utility Owned Generation (UOG) | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | |
| 3 | Tolling Agreements | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | |
| 4 | Energy Imports (Specified) | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | |
| 5 | Energy imports (Unspecified) | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | |
| 6 | Qualifying Facility (QF) Contracts | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | |
| 7 | MJRP Compliance Obligation (Note 2) | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | |
| 8 | **Subtotal** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | |
| 9 | **Indirect GHG Emissions (MTCO2e)** | | | | | | | | | | | | | | | | | | | | |
| 10 | In-state Market Purchases | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | |
| 11 | Contract Purchases | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | |
| 12 | **Subtotal** | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | |
| 13 | **Total Emissions (MTCO2e) (Note 3)** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | |
| 14 | **Weighted Average Cost of Compliance Instrument Inventory ($/MT)** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | |
| 15 | **Proxy GHG Price ($/MT)** | - | - | - | - | 2.26 | - | 13.08 | - | 13.81 | - | 15.27 | - | 16.80 | - | 15.65 | - | 16.47 | | 19.36 | |
| 16 | GHG Costs ($) | | | | | | | | | | | | | | | | | | | | |
| 17 | Direct GHG Costs | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | |
| 18 | Indirect GHG Costs | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | | | | | | | | | | | | | | |
| 19 | Previous Year's Forecast Reconciliation (Line 21) | N/A | N/A | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | |
| 20 | Total Costs ($) | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | |
| 21 | **Forecast Variance ($)** | N/A | [redacted] | N/A | [redacted] | N/A | [redacted] | N/A | [redacted] | N/A | [redacted] | N/A | [redacted] | N/A | [redacted] | N/A | [redacted] | N/A | [redacted] | N/A | |

Notes:

1/ Recorded costs in years between 2013 to 2021 represent the accrued total emissions at the weighted average cost on Exhibit PAC/201.
The actual Multi-Jurisdictional Retail Provider (MJRP) Compliance Obligation for each year is not known until September of the following year

2/ Under the Mandatory Reporting Rule Regulation, PacifiCorp reports emissions associated with using i's retail load
based on a unique formula. As such, PacifiCorp has revised the table to include a new section under "Direct GHG Emissions"
for PacifiCorp to report its MJRP Compliance Obligation on Line 7.

3/ PacifiCorp only has direct emissions and therefore this information is considered confidential.

**CONFIDENTIAL INFORMATION IS SHADED**

Application No. 21-08-_____
Exhibit No. PAC/203
Witness: Mary M. Wiencke

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP 2022 ECAC

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Summary of the GHG Allowance Costs Sub-Balancing Account

CONFIDENTIAL

August 2, 2021

**CONFIDENTIAL**
**Exhibit PAC/203**
**PacifiCorp**
**Summary of the GHG Allowance Costs Sub-Balancing Account**
**August 2, 2021**

| | | GHG Allowance Costs Sub-Balancing Account | | |
|---|---|---|---|---|
| Line No. | Description | Recorded-to-Date (as of 5/31/2021) | Estimated 6/1/20 - 12/31/21 | Estimated 12/31/2021 Balance |
| 1 | GHG Allowance Costs | | | |
| 2 | 2013 | [redacted] | | |
| 3 | Accrued Interest | | | |
| 4 | 2014 | | | |
| 5 | Accrued Interest | | | |
| 6 | 2015 | | | |
| 7 | Accrued Interest | | | |
| 8 | 2016 | | | |
| 9 | Accrued Interest | | | |
| 10 | 2017 | | | |
| 11 | Accrued Interest | | | |
| 12 | 2018 | | | |
| 13 | Accrued Interest | | | |
| 14 | 2019 | | | |
| 15 | Accrued Interest | | | |
| 16 | 2020 | | | |
| 17 | Accrued Interest | | | |
| 18 | 2021 | | | |
| 19 | Accrued Interest | | | |
| 18 | Gross up for Franchise Taxes and Bad Debt Expense[1] | | | [redacted] |
| 20 | Subtotal Recorded/Forecast Costs | | | $ 65,261,421 |
| 21 | GHG Surcharge Collected from Customers | [redacted] | | |
| 22 | GHG Allowance Costs Sub-Balancing Account Under / (Over) Collection | | | [redacted] |

[1] Authorized factor of 98.1867565% applies from 2013 - 2018, and 97.977602% from 2019 forward

**CONFIDENTIAL INFORMATION IS SHADED**

Application No. 21-08-_____
Exhibit No. PAC/204
Witness: Mary M. Wiencke

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP 2022 ECAC

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2022 Forecast Compliance Obligation and GHG Allowance Cost

CONFIDENTIAL

August 2, 2021

**CONFIDENTIAL**
**Exhibit PAC/204**
**PacifiCorp**
**2022 Forecast Compliance Obligation and GHG Allowance Costs**
**August 2, 2021**

| Line No. | Description | Jan | Feb | Mar | Apr | May | June | July | Aug | Sept | Oct | Nov | Dec | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Compliance Obligation (1) | [redacted] | | | | | | | | | | | | |
| 2 | Allowance Price (2) | $19.36 | $19.36 | $19.36 | $19.36 | $19.36 | $19.36 | $19.36 | $19.36 | $19.36 | $19.36 | $19.36 | $19.36 | $19.36 |
| 3 | Compliance Costs | [redacted] | | | | | | | | | | | | |

(1) Volumes are in Metric Tons CO2e. The compliance obligation was developed using data consistent with the system generation mix forecast and California load forecast assumptions in the 2022 ECAC filed as part of this application.
(2) The Company used March 31, 2021 forward ICE settlement price for forecasted GHG allowances with December delivery of the forecast year consistent with forward prices for other commodities in its respective 2022 ECAC filed as part of this application.

**CONFIDENTIAL INFORMATION IS SHADED**

Application No. 21-08-_____
Exhibit No. PAC/205
Witness: Mary M. Wiencke

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP 2022 ECAC

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2020 Recorded GHG Allowance Revenue

CONFIDENTIAL

August 2, 2021

**2020 Recorded GHG Allowance Revenue**
**August 2, 2021**

| Line No. | Description | Volume [1] | Price [2] | Dollars |
|---|---|---|---|---|
| 1 | Auction Date: | | | |
| 2 | February 2020 | [redacted] | $17.87 | [redacted] |
| 3 | May 2020 | | $16.68 | |
| 5 | August 2020 | | $16.68 | |
| 6 | November 2020 | | $16.93 | |
| 8 | Total 2020 | 767,732 | | $ (13,082,153) |

[1] Volumes are in Metric Tons CO2e
[2] Settled Price for the Auction
**CONFIDENTIAL INFORMATION IS SHADED**

Application No. 21-08-_____
Exhibit No. PAC/206
Witness: Mary M. Wiencke

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP 2022 ECAC

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2021 Recorded/Forecast GHG Allowance Revenue

CONFIDENTIAL

August 2, 2021

**Exhibit PAC/206**
**PacifiCorp**
**2021 Recorded/Forecast GHG Allowance Revenue**
**August 2, 2021**

| Line No. | Description | Volume [1] | Price [2] | Dollars |
|---|---|---|---|---|
| 1 | Auction Date: | | | |
| 2 | February 2021 | [redacted] | $17.80 | [redacted] |
| 3 | May 2021 | [redacted] | $18.80 | [redacted] |
| 4 | 2021 Recorded | | | [redacted] |
| 5 | August 2021 | [redacted] | $18.51 | [redacted] |
| 6 | November 2021 | [redacted] | $18.51 | [redacted] |
| 7 | 2021 Forecast | | | [redacted] |
| 8 | Total 2021 | 549,673 | | $ (10,116,732) |

[1] Volumes are in Metric Tons CO2e

[2] The Company used March 31, 2021 forward ICE settlement price for forecasted GHG allowances with December delivery of the forecast year consistent with forward prices for other commodities in its respective 2022 ECAC filed as part of this application.

**CONFIDENTIAL INFORMATION IS SHADED**

Application No. 21-08-_____
Exhibit No. PAC/207
Witness: Mary M. Wiencke

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP 2022 ECAC

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Summary of the GHG Allowance Revenue Balancing Account

CONFIDENTIAL

August 2, 2021

**CONFIDENTIAL**
**Exhibit PAC/207**
**PacifiCorp**
**Summary of the GHG Allowance Revenue Balancing Account**
**August 2, 2021**

| | | GHG Revenue Balancing Account | | | |
|---|---|---|---|---|---|
| Line No. | Description | Recorded-to-Date (as of 5/31/2021) | Estimated 6/1/21 - 12/31/21 | Estimated 12/31/21 Balance | Source |
| 1 | GHG Allowance Revenues: | | | | |
| 2 | 2013 | $ (9,096,948) | | $ (9,096,948) | See A.14-08-003 Confidential Exhibit PAC/104 |
| 3 | Accrued Interest - 2013 | $ (10,510) | | $ (10,510) | |
| 4 | 2014 | $ (8,518,840) | | $ (8,518,840) | See A.15-08-044 Confidential Exhibit PAC/205 |
| 5 | Accrued Interest - 2014 | $ (6,331) | | $ (6,331) | |
| 6 | 2015 | $ (9,085,917) | | $ (9,085,917) | See A.16-08-001 Confidentail Exhibit PAC/205 |
| 7 | Accrued Interest - 2015 | $ 224 | | $ 224 | |
| 8 | 2016 | $ (9,387,611) | | $ (9,387,611) | See A.17-08-005 Confidentail Exhibit PAC/205 |
| 9 | Accrued Interest - 2016 | $ 4,365 | | $ 4,365 | |
| 10 | 2017 | $ (10,681,011) | | $ (10,681,011) | See A.18-08-001 Confidentail Exhibit PAC/205 |
| 11 | Accrued Interest - 2017 | $ 9,052 | | $ 9,052 | |
| 12 | 2018 | $ (11,216,803) | | $ (11,216,803) | See A.19-08-002 Confidentail Exhibit PAC/205 |
| 13 | Accrued Interest - 2018 | $ (28,545) | | $ (28,545) | |
| 14 | 2019 | $ (12,783,641) | | $ (12,783,641) | See A.20-08-002 Confidentail Exhibit PAC/205 |
| 15 | Accrued Interest - 2019 | $ (55,368) | | $ (55,368) | |
| 16 | 2020 | $ (13,082,153) | | $ (13,082,153) | Confidential Exhibit PAC/205 |
| 17 | Accrued Interest - 2020 | $ (20,477) | | $ (20,477) | |
| 18 | 2021 | [redacted] | | $ (10,116,732) | Confidential Exhibit PAC/206 |
| 19 | Accrued Interest - 2021 | | | $ (17,911) | |
| 18 | Gross up for Franchise Taxes and Bad Debt Expense[1] | | | $ (1,781,629) | |
| 20 | Subtotal Recorded/Forecast Revenues | | | $ (95,876,786) | |
| 21 | Recorded/Forecast Expenses: | | | | |
| 22 | GHG Outreach and Education Costs - (2013 - 2021) | $ 492,225 | $ 47,150 | $ 539,375 | Exhibit PAC/301 Line 10 |
| 23 | GHG Administrative Costs - (2013 - 2021) | $ 38,620 | $ 4,010 | $ 42,630 | Exhibit PAC/401 Line 9 |
| 24 | Gross up for Franchise Taxes and Bad Debt Expense[1] | $ 8,938 | $ 1,035 | $ 9,973 | Exhibit PAC/605 Line 11 |
| 25 | Allowance Revenue Approved for Clean Energy or Efficiency Programs[2] | $ 6,468,122 | $ - | $ 6,468,122 | Exhibit PAC/605 Line 14 |
| 26 | Subtotal Forecast Expenses | $ 7,007,905 | $ 52,195 | $ 7,060,100 | |
| 27 | Net GHG Revenues Available for Return (Lines 20 + 26) | | | $ (88,816,686) | |
| 28 | GHG Revenue Amount Returned to Eligible Customers (2013 - 2021) | $ 83,267,828 | 3,533,604.33 | $ 86,801,432 | |
| 29 | GHG Allowance Revenue Balancing Account (Under) / Over | | | $ (2,015,253) | |

[1] Authorized factor of 98.1867565% applies from 2013 - 2018, and 97.977602% from 2019 forward

[2] Commission Decision (D.) 17-12-022 Ordering Paragraph 5 requires PacifiCorp to reserve 10% of the proceeds from the sale of greenhouse gas proceeds for use in the Solar on Multifamily Affordable Housing Program. The set aside started mid-year in 2016 when the company was directed to set aside 5% for half of 2016 and 10% annually thereafter. Also refer to the direct testimony of Ms. Judith M. Ridenour and Line 14 of Ms. Ridenour's Confidential Exhibit PAC/605 which shows the funds set aside for the Program.

**CONFIDENTIAL INFORMATION IS SHADED**

Application No. 21-08-_____
Exhibit No. PAC/208
Witness: Mary M. Wiencke

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP 2022 ECAC

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2022 Forecast GHG Allowance Revenue

CONFIDENTIAL

August 2, 2021

Exhibit No. PAC/208
Confidential Document Subject to
PU Code Section 583 and General Order 66-C


**Exhibit PAC/208**
**PacifiCorp**
**2022 Forecast GHG Allowance Revenue**
**August 2, 2021**

| Line No. | Description | Volume (1) | Price (2) | Dollars |
|---|---|---|---|---|
| 1 | Auction Date: | | | |
| 2 | February 2022 | [redacted] | $19.36 | [redacted] |
| 3 | May 2022 | [redacted] | $19.36 | [redacted] |
| 4 | August 2022 | [redacted] | $19.36 | [redacted] |
| 5 | November 2022 | [redacted] | $19.36 | [redacted] |
| 6 | Total 2022 Forecast | 550,696 | | ($10,661,475) |

(1) Volume is set by California Cap and Trade Regulation Section § 95892. Allocation to Electrical Distribution Utilities for Protection of Electricity Ratepayers. Table 9-4: Annual Allowances Allocated to Each Electrical Distribution Utility from 2021 through 2030. The Annual Allowance allocation may be reduced by CARB to account for EIM Purchaser Emissions. The forecast amount of EIM Purchaser Emissions unknown as of the time of this filing but is expected to be relatively small.

(2) The Company used March 31, 2021 forward ICE settlement price for forecasted GHG allowances with December delivery of the forecast year consistent with forward prices for other commodities in its respective 2022 ECAC filed as part of this application.

**CONFIDENTIAL INFORMATION IS SHADED**

Application No. 21-08-_____
Exhibit No. PAC/209
Witness: Mary M. Wiencke

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP 2022 ECAC

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Commission Template D-5 History of Revenues, Costs, and Emissions Intensity

CONFIDENTIAL

August 2, 2021

**CONFIDENTIAL**
**Exhibit PAC/209**
**PacifiCorp**
**Commission Template D-5**
**History of Revenue, Costs, and Emissions Intensity**
**August 2, 2021**

| Line | | 2013 Actual | 2014 Actual | 2015 Actual | 2016 Actual | 2017 Actuals | 2018 Actuals |
|---|---|---|---|---|---|---|---|
| 1 | **Total GHG Revenues ($) Note 1** | $ (9,106,055) | $ (17,893,007) | $ (12,402,688) | $ (10,185,249) | $ (8,724,275) | $ (10,866,848) |
| 2 | **Total GHG Costs ($) Note 2** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| 3 | **Emissions Intensity (MTCO2e/MWh)** | 0.713 | 0.729 | 0.742 | 0.687 | 0.684 | 0.685 |

Note 1: See Confidential Exhibit PAC/605, Line 17
Note 2: See Confidential Exhibit PAC/202, Line 17

**CONFIDENTIAL INFORMATION IS SHADED**

Application No. 21-08-_____
Exhibit No. PAC/300-304
Witness: Ashley Rask

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP 2022 ECAC

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Direct Testimony of Ashley Rask

August 2, 2021

# Table of Contents



**Attached Exhibits**

## I. Witness Qualifications

**Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or Company).**

A. My name is Ashley Rask. My business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. I am a Senior Communications Representative in the Customer and Corporate Communications department of the Company.

**Q. Briefly describe your education and business experience.**

A. I hold a Bachelor of Arts in English from Portland State University. I joined PacifiCorp in 2017 as a Communications Representative, where I've led the communications for PacifiCorp's energy assistance and regulatory outreach, including bill inserts, mailings and media. From 2015 to 2017, I worked as an Ads Quality Rater at ZeroChaos remotely in Portland, Oregon.

**Q. Please explain your responsibilities as PacifiCorp's Senior Communications Representative.**

A. I primarily oversee PacifiCorp communications for our energy efficiency programs to ensure they are integrated and aligned with the Company's brand and goals, coordinated with regulatory processes, program changes, external communications, social media, traditional media, and other outreach and support.

## II. Summary of Testimony

**Q. Please summarize your testimony.**

A. My testimony reconciles PacifiCorp's forecast and actual recorded 2020 and 2021 customer outreach costs as compared to the forecast set out in PacifiCorp's last application filed August 3, 2020, Application (A.) 20-08-002 (2021 Application). My testimony also forecasts PacifiCorp's 2022 customer outreach costs associated with its participation in California's Cap and Trade Program.

## III. Reconciliation of Forecast and Actual Recorded 2020 and 2021 Customer Outreach Costs

**Q. How much did PacifiCorp spend on customer outreach in 2020?**

A. PacifiCorp recorded $75,268 for outreach in 2020, which is $268 more than the $75,000 projected in PacifiCorp's 2021 Application. See PAC/301.

**Q. Why were 2020 outreach costs higher than anticipated in PacifiCorp's 2021 Application?**

A. An outstanding vendor invoice from PacifiCorp's 2019 outreach was processed in January 2020, making total costs slightly higher than estimated for 2020.

**Q. What is the 2021 customer outreach budget approved by the California Public Utilities Commission (Commission)?**

A. The Greenhouse Gas (GHG)-related costs and allowance proceeds portion of the 2021 Application was approved by the Commission in Decision (D.) 21-03-007. The Commission approved PacifiCorp's proposed customer outreach budget of $80,000 for 2021.[1]

**Q. How much has PacifiCorp spent on customer outreach in 2021?**

A From January 1, 2021 through May 31, 2021, the Company spent $32,850 on customer outreach. PacifiCorp's authorized budget for customer outreach in 2021 is $80,000. Based on that projection, there is $47,150 remaining in the budget to be spent in 2021.[2] The Company plans to undertake additional outreach in October and

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[1] D.21-03-007 at 10.
[2] *See* Exhibit PAC/301.

November of 2021 to coincide with the California Climate Credit distribution. The outreach will include a bill insert, bill message, email, as well as paid radio, digital, social media, and newspaper advertising. The outreach will remind customers to look for the California Climate Credit from the state of California's Cap and Trade Program on their October and November bills. Outreach will encourage them to use the California Climate Credit to achieve more savings by investing in energy-saving upgrades for their homes – for example, new energy-efficient lights, appliances, and weatherization.

## IV. Forecast 2022 Customer Outreach Costs

**Q. What are PacifiCorp's 2022 forecast customer outreach costs?**

A. Based on the customer outreach plan outlined in Exhibit PAC/302, PacifiCorp expects to incur $80,000 in customer outreach costs for 2022, which is the same as 2021. See PAC/302 and PAC/303.

**Q. What is the basis for the forecast customer outreach costs, including the accounting and explanation of activities expected to be undertaken and costs expected to be incurred?**

A. The Company believes this budget will allow for effective communication with customers about the Cap and Trade Program. For 2022, PacifiCorp will continue to actively engage with customers with an integrated, multi-channel campaign designed to build awareness of the GHG revenue returns and the semi-annual California Climate Credit. The outreach will also provide basic information about the value of the Cap and Trade Program and provide ongoing support to help customers learn more about how to adopt and sustain energy-efficient practices to reduce their GHG emissions.

As in prior years, PacifiCorp's 2022 outreach plan will include inserts in customer bills to remind customers about the Cap and Trade Program and the California Climate Credit. To reach customers who receive paperless bills, PacifiCorp will send email communications. PacifiCorp will also place paid radio, digital, social, and newspaper advertising about the California Climate Credit and also communicate with customers through low-cost channels, such as on-bill messages. PacifiCorp will use web-based communication platforms, social media, the Company's customer contact center, and customer-facing employees working in California to communicate with customers.

**Q. Has the Company included Commission Template D-3 with this application?**

A. Yes. Commission Template D-3[3] provides an overview of the customer outreach and program administrative costs, forecast and recorded, from 2013 to 2021. Customer outreach costs are addressed in my testimony and administrative costs are addressed in the testimony of Mr. Anthony B. Worthington. Because these topics are addressed by different PacifiCorp witnesses, the template has been divided into two parts for this submission. Template D-3 – Detail of Outreach Costs is provided as Exhibit PAC/304. Much of this same data may also be found in Exhibits PAC/301, PAC/302, and PAC/303. For Template D-3 – Detail of Administrative Costs, refer to Mr. Worthington's Exhibit PAC/403.

**Q. Does this conclude your direct testimony?**

A. Yes.

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[3] *See* D.14-10-033, D.14-10-055, and D.15-01-024.

Application No. 21-08-_____
Exhibit No. PAC/301
Witness: Ashley Rask

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP 2022 ECAC

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2013 - 2021 Recorded/Forecast Customer Outreach Costs

August 2, 2021

**Exhibit PAC/301**
**PacifiCorp**
**2013 - 2021 Recorded/Forecast Customer Outreach Costs**
**August 2, 2021**

| Line No. | Description | Recorded-to-Date (as of 5/31/2021) | Estimated 6/1/20 - 12/31/21 | Total 12/31/21 |
|---|---|---|---|---|
| 1 | Recorded/Forecast Expenses 2013 - 2021: | | | |
| 2 | GHG Outreach and Education Costs - 2013(1) | $ 1,403 | $ - | $ 1,403 |
| 3 | GHG Outreach and Education Costs - 2014(2) | $ 51,596 | $ - | $ 51,596 |
| 4 | GHG Outreach and Education Costs - 2015(3) | $ 59,748 | $ - | $ 59,748 |
| 5 | GHG Outreach and Education Costs - 2016(4) | $ 82,027 | $ - | $ 82,027 |
| 6 | GHG Outreach and Education Costs - 2017(5) | $ 56,663 | $ - | $ 56,663 |
| 7 | GHG Outreach and Education Costs - 2018(6) | $ 65,690 | $ - | $ 65,690 |
| 8 | GHG Outreach and Education Costs - 2019(7) | $ 66,980 | $ - | $ 66,980 |
| 9 | GHG Outreach and Education Costs - 2020(8) | $ 75,268 | $ - | $ 75,268 |
| 10 | GHG Outreach and Education Costs - 2021(9) | $ 32,850 | $ 47,150 | $ 80,000 |
| 11 | Total | $ 492,225 | $ 47,150 | $ 539,375 |

(1)See A.14-08-003 Exhibit PAC/200 and Exhibit PAC/202 for a discussion about actual GHG outreach and education costs recorded in 2013.

(2) See A.15-08-004 Exhibit PAC/300 and Exhibit PAC 301 for a discussion about actual GHG outreach and education costs recorded in 2014.

(3)See A.16-08-001 Exhibit PAC/300 and Exhibit PAC/301 for a discussion about actual GHG outreach and education costs recorded in 2015.

(4)See A.17-08-005 Exhibit PAC/300 and Exhibit PAC/301 for a discussion about actual GHG outreach and education costs recorded in 2016.

(5)See A.18-08-001 Exhibit PAC/300 and Exhibit PAC/301 for a discussion about actual GHG outreach and education costs recorded in 2017.

(6)See A.19-08-002 Exhibit PAC/300 and Exhibit PAC/301 for a discussion about actual GHG outreach and education costs recorded in 2018.

(7)See A.20-08-002 Exhibit PAC/300 and Exhibit PAC/301 for a discussion about actual GHG outreach and education costs recorded in 2019.

(8)See Exhibit PAC/300, page 2

(9)See PAC/300, page 2-3.

Application No. 21-08-_____
Exhibit No. PAC/302
Witness: Ashley Rask

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP 2022 ECAC

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2022 Customer Outreach Activities and Estimated Costs

August 2, 2021

**Exhibit PAC/302**
**PacifiCorp**
**2022 Customer Outreach Activities and Estimated Costs**
**August 2, 2021**

| **Outreach Activity** | **Description** | **Timing** | **Estimated Cost** |
|---|---|---|---|
| Bill insert | Create regulatory-style bill onsert explaining the program and impact on customer rates and encourage customers to use their credit for energy efficiency upgrades. (combined and costs split with ECAC) | August 2022 | $3,500 |
| Print Ads<br>Mailing to government officials | Place regulatory-style print ads in northern California newspapers and mail letter to city/county officials | August 2022 | $2,300 |
| Talking Points for customer contact center | Update simple talking point to help agents answer customer questions | August 2022 | $0 |
| Bill insert | Print CPUC letter and provide as a bill insert for residential customers about the California Climate Credit | April and October 2022 | $5,000 |
| Email | Provide targeted email to our paperless billing residential customers about the Climate Credit | April and October 2022 | $2,000 |
| Radio | Use English radio spots and targeted Spanish digital radio commercials and media buy to inform customers about California's Climate Credit | April and October 2022 (10 weeks) | $30,000 |

| **Outreach Activity** | **Description** | **Timing** | **Estimated Cost** |
|---|---|---|---|
| Newspaper | Use newspaper advertising to support messages in the radio and bill insert timed around California Climate Credit distribution | April and October 2022 (10 weeks) | $16,000 |
| Digital | Use digital advertising to support messages in the radio and bill insert timed around California Climate Credit distribution. | April and October 2022 | $16,000 |
| Bill message | Include Cap-and-Trade messaging on residential and small business customers' electric bills. On-bill messages are limited to 235 characters & spaces.<br><br>For residential and small business | April and October 2022 for residential customers. All year for small business customers. | $0 |
| Newsletter articles | Include relevant stories in the California editions of existing customer newsletters reaching residential customers. | *Connect newsletter April & October issues 2022* | $0 |
| Direct Mail | Mailing to master-metered customers to inform them of their obligation to pass the California Climate Credit on to tenants in mobile-homes served by a master meter. | Q1 & Q3 | $200 |

| Outreach Activity | Description | Timing | Estimated Cost |
|---|---|---|---|
| Creative Costs | Funding for the print, digitial, social and radio ads that the Company's design agency will assist in creating. | April and October 2022 | $5,000 |
| Social Media | Leverage PacifiCorp's Facebook and Twitter feeds to remind customers about the Climate Credit and provide key facts and sources of additional Cap-and-Trade program information. | Q2 & Q3 | $0 |
| **Total for 2022** | | | **$80,000** |

Application No. 21-08-______
Exhibit No. PAC/303
Witness: Ashley Rask

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

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2022 Forecast Customer Outreach Costs

August 2, 2021

**Exhibit PAC/303**
**PacifiCorp**
**2022 Forecast Customer Outreach Costs**
**August 2, 2021**

| Line No. | Description | Forecast for 2022 |
|---|---|---|
| 1 | Forecast Expenses 2022 | |
| 2 | GHG Outreach and Education Costs - 2022 (See Exhibit PAC/302) | $ 80,000 |
| 3 | Total | $ 80,000 |

Application No. 21-08-_____
Exhibit No. PAC/304
Witness: Ashley Rask

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP 2022 ECAC

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Commission Template D-3 (Note 1)
Detail of Outreach Expenses

August 2, 2021

**Exhibit PAC/304**
**PacifiCorp**
**Commission Template D-3 (Note 1)**
**Detail of Outreach Expenses**
**August 2, 2021**

| | | 2013 | | 2014 | | 2015 | | 2016 | | 2017 | | 2018 | | 2019 | | 2020 | | 2021 (Note 2) | | 2022 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line | Description | Forecast | Recorded | Forecast | Recorded | Forecast | Recorded | Forecast | Recorded | Forecast | Recorded | Forecast | Recorded | Forecast | Recorded | Forecast | Recorded | Forecast | Recorded | Forecast | Recorded |
| 1 | Utility Outreach | | | | | | | | | | | | | | | | | | | | |
| 2 | Detail of outreach activities | 59,748 | 1,403 | 110,000 | 51,596 | 110,000 | 59,748 | 80,000 | 82,027 | 85,000 | 56,663 | 85,000 | 65,690 | 75,000 | 66,980 | 75,000 | 75,268 | 80,000 | 80,000 | 80,000 | |
| 3 | Additional (Non-Utility) Statewide Outreach | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 4 | Total Outreach | 59,748 | 1,403 | 110,000 | 51,596 | 110,000 | 59,748 | 80,000 | 82,027 | 85,000 | 56,663 | 85,000 | 65,690 | 75,000 | 66,980 | 75,000 | 75,268 | 80,000 | 80,000 | 80,000 | - |

Note 1: This is Commission Template D-3. The template provided by the Commission included outreach and administrative costs in the same table. The template has been split into two tables. one for outreach costs and one for admininstrative costs, so that each table may be included as an exhibit for the appropriate Company witness. Exhibit PAC/304 is the detail of outreach costs.
Exhibit PAC/403 is detail of administrative costs, accompanying Mr. Tony Worthington's testimony.
Note 2: Recorded amount includes forecast expenditures for the remainder of 2021.

Application No. 21-08-_____
Exhibit No. PAC/400 – 403
Witness: Anthony B. Worthington

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP 2022 ECAC

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Direct Testimony of Anthony B. Worthington

August 2, 2021

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**Attached Exhibits**

## I. Witness Qualifications

**Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or Company).**

A. My name is Anthony B. Worthington. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. I am the Customer Services manager of billing within the Company.

**Q. Briefly describe your education and business experience.**

A. I hold a Bachelor of Business Administration from the University of Oregon. I joined PacifiCorp in May 1997, and assumed my current position in December 2015.

**Q. Please explain your responsibilities as PacifiCorp's Manager of Billing within Customer Services.**

A. I manage the Company's customer billing services for approximately 1.9 million customers, including complex managed accounts billing, and the customer service billing system's implementation of commission-approved price and rate changes for PacifiCorp's six-state service territory.

## II. Summary of Testimony

**Q. Please summarize your direct testimony.**

A. My testimony reconciles PacifiCorp's actual recorded administrative costs incurred in 2020 and year-to-date through May 31, 2021, as compared to the forecast set out in PacifiCorp's last application filed August 3, 2020, Application (A.) 20-08-002 (2021 Application). My testimony also provides an overview of the administrative costs the Company expects to incur in 2022 for administering the Greenhouse Gas (GHG) Cap and Trade Program (Cap and Trade Program), namely related to the distribution of Climate Credits.

## III. Reconciliation of Forecast and Actual Recorded 2020 and 2021 Administrative Costs

**Q. What were the 2020 GHG Program administrative costs?**

A. The Company incurred $4,440 in Cap and Trade Program administrative costs in 2020, which was less than the $5,600 originally projected in the 2021 Application. *See* Exhibits PAC/401 and PAC/403. The Company tracked the number of checks requested following the distribution of the California Climate Credits in 2020.

**Q. What are the drivers of the administrative costs incurred in 2020?**

A. The Company's administrative costs are driven primarily by the cost to issue checks to customers with a surplus account balance. In 2020, a total of 888 checks were issued to customers with a surplus balance who requested payment via check. The Company estimates the incremental cost for issuing each check to be $5,[1] which represents the cost for the bank to issue and mail a check. At a cost of $5 per check, the total cost for issuing 888 checks in 2020 was $4,440.

**Q. What administrative costs does PacifiCorp expect to incur in 2021?**

A. The budget for 2021 approved in Decision 21-03-007 is $5,600. From January 1, 2021, through May 31, 2021, PacifiCorp has incurred $990 in administrative costs for issuing checks to customers. There is $4,610 remaining in the budget for 2021,

[1] *See* Direct Testimony of Ms. Valerie F. Smith Exhibit PAC/300 at page 3 in A.14-08-003. Administrative costs include the costs for printing and mailing the check and do not include internal labor costs. The Company will continue to monitor this process and if it finds that incremental labor is required, it may include these costs in the future.

however the Company expects to incur $4,010 from June 1, 2021 through the remainder of the year, for a total of $5,000. *See* Exhibit PAC/401. The Company tracked the number of checks requested following the distribution of the California Climate Credit in April 2021. A total of 198 checks were issued to customers with a surplus balance remaining in their account. At a cost of $5, the total cost for issuing checks through May 31 in 2021 was $990. The Company believes it will receive a number of requests after the October-November 2021 distribution resulting in administrative costs equal to at least $5,000 for the year, which is less than the 2021 budget of $5,600.[2] Any difference will be trued-up in the Company's next application filed in August 2022.

## IV. Forecast 2022 Administrative Costs

**Q. What are the 2022 forecast administrative costs?**

A. For 2022, PacifiCorp forecasts that it will incur $5,000 in administrative costs specific to the Cap and Trade Program. This funding is for administrative activities associated with the semi-annual disbursement of the residential California Climate Credit including customer-requested check processing for the surplus account balance. *See* Exhibit PAC/402.

**Q. What is the basis for the 2022 forecast program administrative costs?**

A. The forecasted administrative costs reflect trends in the volume of checks requested in 2020 and anticipated volume of requests in 2021. The number of checks issued in 2020 were lower than 2019 and continued a reduction in customers requesting refunds since the start of the program. PacifiCorp believes this to reflect a preference

[2] *See* D.21-03-007 at 10.

of customers to have the credit applied against their electric account balance rather than returned in a check. Accordingly, the Company forecasts $5,000 for administrative costs in 2022 to cover the costs associated with the issuance of checks.

**Q. Has the Company included Commission Template D-3 with this application?**

A. Yes. Commission Template D-3[3] provides an overview of forecast and recorded customer outreach and program administrative costs from 2013 to 2022. Administrative costs are addressed in my testimony and customer outreach costs are addressed in the testimony of Ms. Ashley Rask. Because these topics are addressed by different PacifiCorp witnesses, the template has been divided into two parts. Template D-3 – Detail of Administrative Costs is provided as Exhibit PAC/403. Much of this same data may also be found in Exhibits PAC/401 and PAC/402. For Template D-3 – Detail of Outreach Costs, refer to Ms. Rask's Exhibit PAC/304.

**Q. Does this conclude your direct testimony?**

A. Yes.

[3] *See* D.14-10-033, D.14-10-055, and D.15-01-024.

Application No. 21-08-_____
Exhibit No. PAC/401
Witness: Anthony B. Worthington

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP 2022 ECAC

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2013 - 2021 Recorded/Forecast Administrative Costs

August 2, 2021

**Exhibit PAC/401**
**PacifiCorp**
**2013 - 2021 Recorded/Forecast Administrative Costs**
**August 2, 2021**

| Line No. | Description | Recorded (as of 5/31/2021) | Estimated 6/1/2021 - 12/31/2021 | Total 12/31/2021 |
|---|---|---|---|---|
| 1 | Recorded/Forecast Expenses 2013 - 2021: | | | |
| 2 | GHG Admnistrative Costs - 2013 [(1)] | $ - | $ - | $ - |
| 3 | GHG Admnistrative Costs - 2014 [(2)] | $ 6,345 | $ - | $ 6,345 |
| 4 | GHG Administrative Costs - 2015 [(3)] | $ 6,580 | $ - | $ 6,580 |
| 5 | GHG Administrative Costs - 2016 [(4)] | $ 5,645 | $ - | $ 5,645 |
| 6 | GHG Administrative Costs - 2017 [(5)] | $ 3,960 | $ - | $ 3,960 |
| 7 | GHG Administrative Costs - 2018 [(6)] | $ 5,015 | $ - | $ 5,015 |
| 8 | GHG Administrative Costs - 2019 [(7)] | $ 5,645 | $ - | $ 5,645 |
| 9 | GHG Administrative Costs - 2020 [(8)] | $ 4,440 | $ - | $ 4,440 |
| 10 | GHG Administrative Costs - 2021 [(9)] | $ 990 | $ 4,010 | $ 5,000 |
| 11 | Other | $ - | $ - | $ - |
| 12 | Total | $ 38,620 | $ 4,010 | $ 42,630 |

(1) See A.14-08-003 Exhibit PAC/300 page 2 for a discussion about actual GHG administrative costs incurred in 2013.

(2) See A.15-08-004 Exhibit PAC/400 page 2 for a discussion about actual GHG administrative costs recorded in 2014.

(3) See A.16-08-001 Exhibit PAC/400 page 2 for a discussion about actual GHG administrative costs recorded in 2015.

(4) See A.17-08-005 Exhibit PAC/400 page 2 for a discussion about actual GHG administrative costs recorded in 2016.

(5) See A.18-08-001 Exhibit PAC/400 page 2 for a discussion about actual GHG administrative costs recorded in 2017.

(6) See A.19-08-002 Exhibit PAC/400 page 2 for a discussion about actual GHG administrative costs recorded in 2018.

(7) See A.20-08-002 Exhibit PAC/400 page 2 for a discussion about actual GHG administrative costs recorded in 2019.

(8) See Exhibit PAC/400 page 2-3.

(9) See Exhibit PAC/400 page 2-3.

Application No. 21-08-_____
Exhibit No. PAC/402
Witness: Anthony B. Worthington

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP 2022 ECAC

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2022 Forecast Administrative Costs

August 2, 2021

**Exhibit PAC/402**
**PacifiCorp**
**2022 Forecast Administrative Costs**
**August 2, 2021**

| Line No. | Description | Forecast for 2022 |
|---|---|---|
| 1 | Forecast Expenses 2022 | |
| 2 | GHG Administrative Costs [(1)] | $ 5,000 |
| 3 | Total | $ 5,000 |

[(1)] See Exhibit PAC/400 page 3-4.

Application No. 21-08-_____
Exhibit No. PAC/403
Witness: Anthony B. Worthington

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP 2022 ECAC

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Commission Template D-3 (Note 1)
Detail Administrative Costs

August 2, 2021

**Exhibit PAC/403**
**PacifiCorp**
**Commission Template D-3 (Note 1)**
**Detail of Administrative Costs**
**August 2, 2021**

| | 2013 | | 2014 | | 2015 | | 2016 | | 2017 | | 2018 | | 2019 | | 2020 | | 2021 (Note 2) | | 2022 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line Description | Forecast | Recorded | Forecast | Recorded | Forecast | Recorded | Forecast | Recorded | Forecast | Recorded | Forecast | Recorded | Forecast | Recorded | Forecast | Recorded | Forecast | Recorded | Forecast | Recorded |
| 1 Utility Administrative | | | | | | | | | | | | | | | | | | | | |
| 2 Detail of administrative activities | - | - | - | 6,345 | 5,000 | 6,580 | 7,500 | 5,645 | 7,000 | 3,960 | 5,000 | 5,015 | 4,500 | 5,645 | 5,100 | 4,440 | 5,600 | 5,000 | 5,000 | - |
| 3 Total Administrative Expenses | - | - | - | 6,345 | 5,000 | 6,580 | 7,500 | 5,645 | 7,000 | 3,960 | 5,000 | 5,015 | 4,500 | 5,645 | 5,100 | 4,440 | 5,600 | 5,000 | 5,000 | - |

Note 1: This is Commission Template D-3. The template provided by the Commission included outreach and administrative costs in the same table. The template has been split into two tables, one for outreach costs and one for admininstrative costs, so that each table may be included as an exhibit for the appropriate Company witness. Exhibit PAC/304 provided with the testimony of Ms. Rask is the detail of outreach costs. Exhibit PAC/403 is detail of administrative costs.

Note 2: Recorded amount includes forecast expenditures for the remainder of 2021.

Application No. 21-08-_____
Exhibit No. PAC/500
Witness: Dana M. Ralston

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP 2022 ECAC

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Direct Testimony of Dana M. Ralston

HIGHLY CONFIDENTIAL

[PUBLIC VERSION]

August 2, 2021

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**Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or Company).**

A. My name is Dana M. Ralston. My business address is 1407 West North Temple, Suite 210, Salt Lake City, Utah 84116. My title is Senior Vice President of Thermal Generation and Mining.

## I. QUALIFICATIONS

**Q. Briefly describe your education and professional experience.**

A. I have a Bachelor of Science Degree in Electrical Engineering from South Dakota State University. I was previously Vice President of Coal Generation and Mining from March 2015 to November 2017, and Vice President of Thermal Generation from January 2010 to March 2015. For 29 years before that, I held a number of positions of increasing responsibility within Berkshire Hathaway Energy's generation organization, including plant manager at the Neal Energy Center generating complex. In my current role, I am responsible for operating and maintaining PacifiCorp's coal- and gas-fired generation fleet, coal fuel supply, and mining.

**Q. Have you testified in previous regulatory proceedings?**

A. Yes. I have provided testimony on behalf of the Company in proceedings before the Public Utilities Commission of the State of California (Commission) and the public utility commissions of Oregon, Utah, Washington, and Wyoming.

## II. PURPOSE AND SUMMARY OF TESTIMONY

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

A. In its approval of the Company's 2020 Energy Cost Adjustment Clause (ECAC) rates in Decision (D.) 20-12-004, the Commission directed PacifiCorp to (1) provide testimony with its annual ECAC application addressing the prudence of any new coal supply agreements (CSAs) executed after the record was submitted in the ECAC filing from the previous year; and (2) to provide a report in its 2022 ECAC Application that addresses "the minimum take provisions included in its long-term CSAs (with terms of five years or longer), including whether any of the clauses should be invoked, as well as the associated ratepayer savings."[1]

My testimony addresses the fact that no new CSAs have been entered into since the record was submitted in the 2021 ECAC and provides the details requested by the Commission is D.20-12-004 regarding the two existing long-term CSAs, which are at the Huntington generating facility and the Hayden generating facility[2] .

## III. NEW COAL SUPPLY AGREEMENTS

**Q. Has PacifiCorp entered into any new CSAs since the record was submitted in the 2021 ECAC?**

A. No. If PacifiCorp enters into a new CSA during the pendency of this proceeding, PacifiCorp will notify parties when the CSA is executed and work with them to identify the appropriate review process. Further, PacifiCorp will file required information regarding the prudency of any new CSAs with its rebuttal testimony.

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[1] *In the Matter of the Application of PacifiCorp (U901E) for Approval of its 2020 Energy Cost Adjustment Clause and Greenhouse Gas-Related Forecast and Reconciliation of Costs and Revenue,* D.20-12-004 at 24-25 (Dec 7, 2020).

[2] The current CSA at the Colstrip facility runs to December 31, 2024 with the option of a one-year extension. However, as the remaining term is less than 5 years, it is not addressed in this testimony.

## IV. THE HUNTINGTON COAL SUPPLY AGREEMENT

**Q. Please provide an overview of the Huntington CSA.**

A. The Company negotiated the Huntington CSA in 2014 and 2015 and executed the contract in 2015. The CSA's term extends to 2029. As was explained in the record in A.15-09-007, the Huntington CSA was a critical element of the Company's decision to close the Deer Creek mine. Without the reliable coal supply for the plant provided by the Huntington CSA, the Company could not have closed the mine. The Commission found at the time that "the new long-term contract with Bowie to supply coal to the Huntington power plant is expected to reduce operating costs through lower sulfur content, while also including provisions that protect PacifiCorp against obligations to continue purchasing coal in the event of new laws, rules or regulations."[3]

**Q. Have the costs incurred in association with the Huntington CSA been reflected in prior ECACs?**

A. Yes, the Huntington CSA has been reflected in customer rates since 2016.

**Q. What information did the Company consider when negotiating the minimum take levels in the Huntington CSA?**

A. PacifiCorp looked at the forecasted generation for the remaining life of the Huntington plant. When the Company negotiated the Huntington CSA, the minimum take level represented approximately [Begin Confidential] [redacted] [End Confidential] of the forecasted plant generation developed using the information available in 2014 and 2015 when the Company negotiated and executed the CSA.

[3] *In the Matter of the Application of PacifiCorp (U901E) for Authority to Sell Certain Mining Assets in Accordance with Public Utilities Code Section 851*, D.18-09-008 at 22-23.

**Q. Does the Huntington CSA allow the Company to terminate or reduce coal purchases in the agreement if environmental laws or regulations affect the economics of the plant?**

A. Yes, generally speaking. Article 8 of the CSA allows the Company to [Begin Highly Confidential] [redacted] [End Highly Confidential]

In docket UM 1712 in Oregon, the Company explained:

> The Company negotiated Article 8 in recognition of the uncertainty now inherent in the environmental regulation of coal generation. The Company's intent was to secure broad flexibility in responding to the impact of the changing environmental regulations or settlements on Huntington, including the ability to terminate the CSA without liquidated damages if future changes in applicable environmental requirements affect the Company's ability to operate Huntington as a coal-fired facility . . . The Company intended Article 8 to address a scenario where an environmental requirement made the continued operation of the plant as a coal-fired facility uneconomic.[4]

**Q. Has legislation like the 100 percent clean electricity laws passed in California (Senate Bill (SB) 350), Washington (SB 5116) and Oregon (SB 1547), which also phase out coal plants provide a basis to terminate the CSA?**

[4] *In the Matter of PacifiCorp dba Pacific Power, Application for Approval of Deer Creek Mine Transaction*, Docket No. UM 1712, Or. Pub. Util. Comm'n, PAC/500, Crane/6 (Mar. 19, 2015).

A. No. The Company does not have the right to terminate the Huntington CSA based on the laws cited above. The effects of an environmental regulation must be more directly applicable to the Huntington plant; the potentially indirect impact on Huntington from clean energy legislation is not a basis to seek termination of the CSA. To the extent the Company can establish a clear connection between an implemented regulation and its effects on the operation of the Huntington plant, including economic effects, then the Company believes the exercise of the Article 8 rights would be warranted and defensible. The potential impacts resulting from the legislation cited above, however, appear to be largely speculative and remote, and lack any direct, causal link between the environmental regulation and the effects on the plant. As such, the resultant effects, if any, would likely be an indefensible basis to trigger the rights provided for under Article 8.

**Q. At this time, are you aware of any other current or anticipated environmental statutes or regulations that might allow the Company to terminate the coal supply agreement pursuant to Article 8?**

A. No.

**Q. Would termination of this contract result in costs to customers?**

A. Yes, the termination of this contract would result in an unjustified cost to customers. If the Company were to terminate the existing agreement, the Company would likely not be able to replace the existing supplier, [Begin Confidential] [redacted] [End Confidential], with other supplier(s) that can provide the quantity and quality of coal required to operate the plant. The Utah coal market does not have a high degree of liquidity. [Begin Confidential] [redacted] [End Confidential] is the largest supplier of low sulfur coal in Utah. The Company is already purchasing Utah's other low sulfur coal supplier's [Begin Confidential] ([redacted]) [End Confidential] production for the Hunter plant under a four-year coal supply agreement that was executed in 2020. Termination and renegotiation is risky and would likely not improve the economics of the plant or be in customers' interest.

**Q. Are there circumstances where the Company would recommend exercising Article 8 of the Huntington CSA?**

A. There may be future circumstances that would properly lead the Company to terminate the coal supply agreement pursuant to Article 8. These circumstances would include a new environmental rule or regulation where a negative economic effect on the Huntington plant could be substantiated and where termination could be demonstrated to be in the customers' interest.

## V. THE HAYDEN COAL SUPPLY AGREEMENT

**Q. Please provide an overview of the Hayden CSA.**

A. PacifiCorp is a minority owner in the Hayden generating facility (17.5 percent), along with Public Service Company of Colorado (PSCo) and the Salt River Project (SRP). PacifiCorp negotiated the CSA in collaboration with PSCo and SRP in order to secure future fuel requirements for Hayden from the nearby Twenty-mile mine owned and operated by Peabody Energy Corporation. The CSA was finalized and executed on December 12, 2011 and runs to December 31, 2027. Hayden has two units; Unit 2 is scheduled for closure in 2027 and Unit 1 is scheduled for closure in 2028.

**Q. Have the costs incurred in association with the Hayden CSA been reflected in prior ECACs?**

A. Yes, the Hayden CSA has been reflected in customer rates since 2012.

**Q. What information did the Company consider when negotiating the minimum take levels in the Hayden CSA?**

A. At the time that the Hayden CSA was being negotiated with the other Hayden plant owners, PacifiCorp looked at the plant's forecasted generation. PacifiCorp's share of the annual minimum tonnage requirement represented only [Begin Confidential] [redacted] [End Confidential] of the forecasted plant generation requirement from 2011 to 2020.

**Q. Can the Hayden CSA be terminated if environmental laws or regulations affect the economics of the plant?**

A. Only if the laws or regulations make operation of the plant [Begin Highly Confidential] [redacted] [End Highly Confidential]

**Q. Has legislation like the 100 percent clean electricity laws passed in California (SB 350), Washington (SB 5116) and Oregon (SB 1547), which also phase out coal plants provide a basis to terminate the CSA?**

A. No, these changes in the laws have not made the operation of the plant or performance of the buyer's material obligations [Begin Highly Confidential] [redacted]. [End Highly Confidential]

**Q. Since Hayden is a jointly-owned facility, how would the exercise of this provision work in practice?**

A. The determination about whether the change in law would result in the [Begin Highly Confidential] [redacted] [End Highly Confidential] PacifiCorp is unable to exercise any provision of the CSA unilaterally.

**Q. At this time, are you aware of any other current or anticipated environmental statutes or regulations that would cause the termination of the coal supply agreement?**

A. No.

**Q. Does this conclude your direct testimony?**

A. Yes.

Application No. 21-08-_____
Exhibit No. PAC/600 - 607
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP 2022 ECAC

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Direct Testimony of Judith M. Ridenour

PUBLIC VERSION

August 2, 2021

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**Attached Exhibits**

## I. Witness Qualifications

**Q. Please state your name, business address, and position with PacifiCorp d/b/a Pacific Power (PacifiCorp or Company).**

A. My name is Judith M. Ridenour. My business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. My present position is Specialist, Pricing & Cost of Service, in the Regulation Department.

**Q. Briefly describe your education and professional background.**

A. I hold a Bachelor of Arts degree in Mathematics from Reed College. I joined the Company in the Regulation Department in October 2000.

**Q. Please describe your current duties.**

A. I am responsible for the preparation of rate spread and rate design used in retail price filings and related analyses. Since 2001, with levels of increasing responsibility, I have analyzed and implemented rate spread and rate design proposals throughout the Company's six-state service territory. I have presented testimony on behalf of the Company in California and Oregon.

## II. Summary of Testimony

**Q. Please summarize your direct testimony.**

A. I present the proposed rate spread and rate design for the Company's Energy Cost Adjustment Clause (ECAC) rate schedule, greenhouse gas (GHG) allowance cost recovery rate schedule and for the California Climate Credit rate schedule. The proposed ECAC rate spread and rate design are consistent with the methodology first implemented in the Company's 2005 general rate case[1] and used in the Company's

[1] Application (A.) 05-11-022, Decision (D.) 06-12-011.

previous ECAC filings. The proposed GHG rate spread and rate design are consistent with Decisions (D.)12-12-033, D.13-12-002 and D.13-12-003 which set forth the Commission's methodologies for collecting GHG allowance costs and distributing GHG allowance revenues to customers. The GHG proposed rate spread and rate design are also consistent with previous GHG filings. The proposed rate spreads and rate designs are based on the 2019 forecast test year, consistent with the Company's most recent general rate case.[2]

The estimated combined effect of the proposed ECAC and GHG cost recovery rates is summarized in the following table:[3]

| **Customer Class** | **Proposed Price Change** | |
|---|---|---|
| | **Dollars** | **Percent (%)** |
| Residential | -$901,000 | -1.6% |
| Commercial/Industrial | -$872,000 | -2.3% |
| Irrigation | -$270,000 | -2.0% |
| Lighting | $1,000 | 0.1% |
| Overall | -$2,042,000 | -1.9% |

The table above does not reflect the California Climate Credit. The proposed residential California Climate Credit for 2022 is $154.58. Consistent with the industry assistance factor applied in 2020 based on D.13-12-002 and applied in 2021 based on D.20-10-002, PacifiCorp's application includes a Small Business California

[2] A.18-04-002
[3] Shows effect of proposed rates in comparison to currently effective rates – for the GHG cost recovery rate, this reflects rates approved in D.21-03-007 (2021 Application) and for the ECAC rate, this reflects rates approved in D.20-12-004 (2020 Application).

Climate Credit for 2022 which offsets 50 percent of the surcharge Small Business customers will pay in 2022 for GHG cost recovery.[4]

## III. ECAC Adjustment Rates

**Q. Please explain the Deferred ECAC adjustment rates.**

A. The Deferred ECAC adjustment rates are rates by rate schedule that are calculated based on the Balancing Rate. Deferred ECAC rates for residential, small general service under 20 kilowatts (kW), and lighting schedules are energy-based rates, and Deferred ECAC rates for the general service 20 kW and above and irrigation rate schedules consist of both a demand-based rate and an energy-based rate.

**Q. What is the proposed Balancing Rate in this case?**

A. As discussed in the direct testimony of Mr. Douglas R. Staples, the proposed Balancing Rate is $4.25 per megawatt-hour (MWh) or 0.425 cents per kilowatt-hour (kWh).

**Q. Have you prepared an exhibit showing the calculation of the proposed Deferred ECAC adjustment rates under the Company's proposal?**

A. Yes. Exhibit PAC/601 shows the calculation of the proposed demand- and energy-based Deferred ECAC adjustment rates by rate schedule in rows 14 through 21.

**Q. Please explain how the proposed Deferred ECAC adjustment rates by rate schedule are calculated.**

A. The Deferred ECAC adjustment rates were calculated using the Balancing Rate for

[4] A proposed decision was issued on July 15, 2021, in Rulemaking 20-05-002 which may change the California Climate Credit applied to Small Business customers to a per customer biannual credit, similar to the Residential California Climate Credit. If such decision impacts the small business credit for 2022, PacifiCorp will update its proposed 2022 California Climate Credits as directed by the Commission.

calendar year 2022. This is consistent with the methodology first implemented in the Company's 2005 general rate case[5] and used in the Company's previous ECAC filings. The proposed Deferred ECAC rates by rate schedule are derived by first multiplying the proposed Balancing Rate by the total forecast kilowatt-hours (kWh) for each schedule. Those revenues are allocated between demand and energy, consistent with the June 2017 Results of Operations from the Company's most recent general rate case.[6] Finally, demand and energy rates for each rate schedule are calculated by dividing the appropriate revenue for each function by its corresponding billing quantities, adjusted to account for tariff discounts.

**Q. Please explain the Projected ECAC adjustment rates.**

A. The Projected ECAC adjustment rates are rates by rate schedule that are calculated based on the Offset Rate. Projected ECAC rates for residential, small general service under 20 kW (kilowatts), and lighting schedules are energy-based rates. Projected ECAC rates for the general service 20 kW and above and irrigation rate schedules consist of both a demand-based rate and an energy-based rate.

**Q. What is the proposed Offset Rate in this case?**

A. As discussed in the direct testimony of Mr. Staples, the proposed Offset rate is $25.15 per MWh or 2.515 cents per kWh.

**Q. Have you prepared an exhibit showing the calculation of the proposed Projected ECAC adjustment rates under the Company's proposal?**

A. Yes. Exhibit PAC/601 shows the calculation of the proposed demand- and energy-based Projected ECAC adjustment rates by rate schedule in rows 22 through 29.

[5] A.05-11-022, D.06-12-011.
[6] A.18-04-002.

**Q. Please explain how the proposed Projected ECAC adjustment rates by rate schedule are calculated.**

A. The Projected ECAC adjustment rates were calculated using the Offset Rate for calendar year 2022. This is consistent with the methodology first implemented in the Company's 2005 general rate case[7] and used in the Company's previous ECAC filings. The proposed Projected ECAC rates by rate schedule are derived by first multiplying the proposed Offset Rate by the total forecast kWh for each schedule. Those revenues are allocated between demand and energy, consistent with the June 2017 Results of Operations from the Company's most recent general rate case.[8] Finally, demand and energy rates for each rate schedule are calculated by dividing the appropriate revenue for each function by its corresponding billing quantities, adjusted to account for tariff discounts.

## IV. Collection of GHG Allowance Costs

**Q. What is the total amount of GHG allowance costs to be recovered in rates in 2022?**

A. The total amount of GHG allowance costs to be recovered in rates in 2022 is $11,049,309 as shown in Confidential Exhibit PAC/602, line six. This amount consists of the forecast 2022 costs, plus a true up related to actual costs for prior years. The amount has been adjusted to account for franchise fees and uncollectibles at the Company's current factor. The amounts in Confidential Exhibit PAC/602 which make up the GHG allowance costs reference the exhibits of other Company witnesses sponsoring those amounts.

[7] A.05-11-022, D.06-12-011.
[8] A.18-04-002.

**Q. How does the Company propose to collect GHG allowance costs from customers?**

A. The Company proposes to continue to collect GHG allowance costs through energy-based adjustment rates in Schedule GHG-92, Surcharge to Recover Greenhouse Gas Carbon Pollution Permit Cost (GHG Surcharge) which was first implemented in 2014 to collect GHG allowance costs. Consistent with the approved rate spread in the Company's previous GHG proceedings, the Company proposes a rate spread allocated on total present base revenues including net power costs. The GHG allowance costs rate spread and rate design are consistent with D.12-12-033, D.13-12-002 and D.13-12-003, which set forth the Commission's methodologies for collecting GHG allowance costs and distributing GHG allowance revenues to customers.

**Q. Have you prepared an exhibit which shows the proposed rates for the GHG Surcharge?**

A. Yes. Exhibit PAC/604 shows the calculation of proposed rates for the GHG Surcharge. Columns 6 and 7 in the exhibit show the rate spread amongst the customer rate schedules and column 8 shows the proposed surcharge rates.

## V. Distribution of GHG Allowance Revenues

**Q. What is the total amount of GHG allowance revenues, net of expenses, to be distributed to eligible customers through the California Climate Credit in 2022?**

A. The total amount to be distributed to eligible customers through the California Climate Credit in 2022 is $11,739,478 as shown in Exhibit PAC/603, line 12. This amount consists of the forecast 2022 revenues offset by the forecast 2022 administrative and outreach costs for the Cap and Trade program, plus a true up related to actual revenues and administrative and outreach costs for previous years, and, consistent with D.17-12-022 and D.20-04-012, an allowance revenue set aside for the Solar on Multifamily Affordable Housing Program. The amounts have been adjusted to account for franchise fees and uncollectibles at the Company's current factor. The amounts in Exhibit PAC/603 are referenced in the testimony and exhibits of other Company witnesses sponsoring those amounts.[9]

**Q. Which customers are eligible to receive a portion of the GHG allowance revenues?**

A. As ordered in D.12-12-033, three types of customers are eligible to receive a portion of the GHG allowance revenues: Energy-Intensive Trade-Exposed entities (EITE), Residential customers and Small Business customers. For PacifiCorp, Small Business customers are defined in D.13-12-003 as all customers served under Schedule A-25, General Service Less than 20kW, and customers served under Schedule PA-20, Agricultural Pumping Service, with demand which has not exceeded 20 kW in more than three months within a 12-month period.

**Q. Does PacifiCorp have any EITE customers?**

A. No. PacifiCorp is not aware of any EITE entities eligible to receive GHG allowance revenue in its service territory; therefore the total allowance revenue estimated for distribution to EITE customers is $0.

**Q. What methodology is used to distribute the GHG allowance revenues to eligible customers?**

[9] See 'Source' column of Exhibit PAC/603.

A. In D.12-12-033, the Commission set forth the methodology for utilities to distribute GHG allowance revenues to customers as an on-bill credit called the California Climate Credit. The credit goes to eligible EITE, Small Business, and Residential customers. As mentioned above, PacifiCorp currently has no EITE customers to receive the credit. In previous applications, Small Business customers received a credit equal to the amount of GHG allowance costs in their rates (the GHG Surcharge) multiplied by the assistance factor for the associated year set forth in Table 2 of Appendix 2 of D. 13-12-002.[10] The final year shown in the table was 2020 with an assistance factor of 50 percent. D.20-10-002 directed PacifiCorp to continue to apply a 50 percent assistance factor in 2021. PacifiCorp has continued this 50 percent assistance factor for 2022 in this application but seeks guidance on whether the Company should continue to use the assistance factor of 50 percent for future applications. The Small Business credit is applied as a line-item, per kWh credit on customers' monthly bills.[11] Per D.12-12-033, PacifiCorp does not have a volumetric residential credit; therefore, the remainder of PacifiCorp's GHG allowance revenue distribution will go to residential customers through a semi-annual, per-household credit as set forth in the decision.

**Q. Have you prepared an exhibit which shows the proposed rates for the California Climate Credit?**

A. Yes. The calculation of the proposed California Climate Credit rates is shown alongside the calculation of the GHG Surcharge rates in Exhibit PAC/604. Column

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[10] On July 1, 2014, the California Air Resources Board implemented the delay in assistance factors contemplated in D.13-12-002 resulting in Table 2 of Appendix 2 being the appropriate table for Small Business Assistance Factors used to calculate the California Climate Credit.

[11] See footnote 3 above regarding pending changes to the Small Business Climate Credit.

10 in the exhibit shows the proposed California Climate Credit rates and column 11 shows in dollars the total credit for each eligible customer type.

**Q. What is the total amount of the proposed Small Business California Climate Credit?**

A. The total amount of the proposed Small Business California Climate Credit to be distributed in 2022 based on a 50 percent assistance factor is $594,532.

**Q. What is the total amount of the proposed residential California Climate Credit and what is the proposed semi-annual, per-household residential bill credit?**

A. The total amount of the proposed residential California Climate Credit to be distributed in 2022 is $11,144,946. The proposed semi-annual, per-household California Climate Credit is $154.58. The proposed credits will be distributed to residential customers[12] in April and October 2022 as required by D.13-12-003, resulting in a total per-household distribution of $309.16 for the year. The proposed semi-annual credit is approximately $57 more than the 2021 residential credit.

**Q. Please explain Confidential Exhibit PAC/605.**

A. Confidential Exhibit PAC/605 is the Commission Template D-1, Annual Allowance Revenue Receipts and Customer Returns, adopted in D.14-10-033. The table summarizes forecast and recorded annual amounts related to GHG allowance revenues. The Company witness supporting each section of the table is shown in the exhibit.

[12] Including customers on tariff Schedule D, Schedule DL-6, Schedule DS-8, Schedule DM-9, and residential customers on Schedule NEM-35. Eligible residential customers are defined as customers with an active account receiving electrical service from PacifiCorp at the time the California Climate Credit is distributed. The submetered systems of master metered customers are also eligible to receive the semi-annual California Climate Credit.

## VI. Rate Impacts

**Q. What is the impact of the proposed changes to the ECAC rates?**

A. The impact of the proposed change to the ECAC Balancing Rate is a rate decrease of approximately $2.4 million over the amount collected through present rates. The impact of the proposed change to the ECAC Offset Rate is a rate decrease of approximately $3.0 million from the amount collected through present rates. Present rates do not reflect ECAC changes proposed in the Company's pending 2021 ECAC application, A.20-08-002.

**Q. What is the impact of the proposed changes to the GHG Surcharge rates?**

A. The impact of the proposed changes to the GHG Surcharge rates is a rate increase of approximately $3.4 million.

**Q. Please describe Exhibit PAC/606.**

A. Exhibit PAC/606 is Commission Template D-4, Forecast Revenue Requirement and Revenues by Rate Schedule. The exhibit summarizes by customer rate schedule the proposed GHG allowance costs to be recovered from customers, the proposed rate per kWh to be applied to customers to recover those costs and the proposed Climate Credit amounts to be distributed to eligible customers. Columns from the template for unbundled customers are not included because PacifiCorp does not have unbundled customers in California.

**Q. What are the overall combined effects of the Company's proposed ECAC and GHG allowance costs rate change?**

A. The overall effects of the proposed ECAC and GHG allowance costs rate change from rates presently in effect are shown in Exhibit PAC/607 and are summarized in the following table:

| Customer Class | Proposed Price Change | |
|---|---|---|
| | Dollars | Percent (%) |
| Residential | -$901,000 | -1.6% |
| Commercial/Industrial | -$872,000 | -2.3% |
| Irrigation | -$270,000 | -2.0% |
| Lighting | $1,000 | 0.1% |
| Overall | -$2,042,000 | -1.9% |

The rate impacts shown in the exhibit and the table exclude the effects of the California Climate Credit.

**Q. Please describe Exhibit PAC/607.**

A. Exhibit PAC/607 shows the effects of the Company's proposed combined ECAC and GHG cost recovery rate change by rate schedule. Columns 5 through 9 show present revenues. Present base revenues are shown in column 5. Present Projected ECAC revenues are shown in column 6. Column 7 adds columns 5 and 6 for total present base revenues including Projected ECAC. The adders in column 8 include revenues for adjustment schedules that are not a part of base revenues including the present Deferred ECAC and present GHG Surcharge. Column 9 adds columns 7 and 8 to show present revenues net of adders. Pass through adjustments such as the Surcharge to Fund Residential California Alternative Rates for Energy (CARE), CARE discounts, and the California Climate Credit are excluded from revenues in this table.

Similarly, for proposed revenues, columns 10 through 14 show the base proposed revenues, proposed Projected ECAC revenues, proposed total base revenues with Projected ECAC, proposed adders including the proposed Deferred ECAC and proposed GHG Surcharge, and proposed net revenues. The proposed base rate change in dollars and percentage is shown by rate schedule in columns 15 and 16. The proposed net rate change in dollars and percentage is shown by rate schedule in columns 17 and 18.

**Q. Does this conclude your direct testimony?**

A. Yes.

Application No. 21-08-_____
Exhibit No. PAC/601
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP 2022 ECAC

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Calculation of Proposed ECAC Adjustment Rates

August 2, 2021

**Exhibit PAC/601**
**PACIFICORP**
**STATE OF CALIFORNIA**
**CALCULATION OF PROPOSED ECAC ADJUSTMENT RATES**

**California Results of Operations June 2017**
**Net Power Costs**
**FERC Account Basis for Allocation of ECAC**

| Line No. | FERC ACCT | Description | PITA Factor | CALIFORNIA Normalized1 | Production | Transmission | Demand % | Production Demand | Production Energy | Transmission Demand | Transmission Energy |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | **Revenue Credits** | | | | | | | | | |
| 1 | 447 | Sales for Resale | SG | $3,066,538 | $3,066,538 | $0 | 75% | $2,299,903 | $766,634 | $0 | $0 |
| | | **Expenses** | | | | | | | | | |
| 2 | 501 | Fuel Related | SE | $11,495,032 | $11,495,032 | $0 | 0% | $0 | $11,495,032 | $0 | $0 |
| 3 | 503 | Steam From Other Sources | SE | $68,933 | $68,933 | $0 | 0% | $0 | $68,933 | $0 | $0 |
| 4 | 547 | Fuel | SE | $3,461,054 | $3,461,054 | $0 | 0% | $0 | $3,461,054 | $0 | $0 |
| 5 | 555 | Purchased Power | SG | $8,342,037 | $8,342,037 | $0 | 75% | $6,256,528 | $2,085,509 | $0 | $0 |
| 6 | 555 | Purchased Power | SE | $114,887 | $114,887 | $0 | 0% | $0 | $114,887 | $0 | $0 |
| 7 | 555 | Purchased Power | SSGC | $0 | $0 | $0 | 75% | $0 | $0 | $0 | $0 |
| 8 | 565 | Transmission of Electricity by Others | SG | $2,036,319 | $0 | $2,036,319 | 75% | $0 | $0 | $1,527,239 | $509,080 |
| 9 | 565 | Transmission of Electricity by Others | SE | $36,804 | $0 | $36,804 | 0% | $0 | $0 | $0 | $36,804 |
| 10 | | Total NPC Accounts | | $22,488,528 | $20,415,405 | $2,073,123 | | $3,956,625 | $16,458,780 | $1,527,239 | $545,884 |
| 11 | | **Total NPC Factors** | | | | | | 18% | 73% | 7% | 2% |

**CALCULATION OF ECAC ADJUSTMENT RATES**

12 **Balancing Rate:** **0.425 ¢/kWh**
13 **Offset Rate:** **2.515 ¢/kWh**

| Line | Class / Schedule | Description | Forecast 2019 KWH (1) | Balancing Rate (2) | Total Deferred Revenues (3) (1)x(2) | Deferred Revenues by ECAC Factor: Production Demand (4) 18% | Production Energy (5) 73% | Transmission Demand (6) 7% | Transmission Energy (7) 2% | Effective kW[1] (8) | Effective kWh[1] (9) | Deferred ECAC: Demand Rate per kW (10) [(4)+(6)]/(8) | Energy Rate per kWh (11) [(5)+(7)]/(9)[2] |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 14 | D/DS-8/DM-9 | Residential Service | 369,549,678 | $0.00425 | $1,570,586 | $276,328 | $1,149,472 | $106,662 | $38,124 | | 369,233,274 | | 0.425 ¢ |
| 15 | A-25 | Small General Service - < 20 kW | 51,917,789 | $0.00425 | $220,651 | $38,821 | $161,489 | $14,985 | $5,356 | | 51,916,281 | | 0.425 ¢ |
| 16 | A-32 | Small General Service - 20 kW & Over | 67,115,094 | $0.00425 | $285,239 | $50,185 | $208,759 | $19,371 | $6,924 | 345,240 | 67,113,000 | $0.20 | 0.321 ¢ |
| 17 | A-36 | Large General Service - 100 kW & Over | 80,107,394 | $0.00425 | $340,456 | $59,900 | $249,171 | $23,121 | $8,264 | 196,263 | 80,095,236 | $0.42 | 0.321 ¢ |
| 18 | AT-48 | Large General Service - 500 kW & Over | 81,372,934 | $0.00425 | $345,835 | $60,846 | $253,108 | $23,486 | $8,395 | 208,998 | 81,121,286 | $0.40 | 0.322 ¢ |
| 19 | PA-20 | Agricultural Pumping Service | 94,292,504 | $0.00425 | $400,743 | $70,507 | $293,294 | $27,215 | $9,728 | 420,637 | 94,292,504 | $0.23 | 0.321 ¢ |
| 20 | | Total Lighting | 3,104,619 | $0.00425 | $13,195 | $2,321 | $9,657 | $896 | $320 | | 3,104,619 | | 0.425 ¢ |
| 21 | | Total | 747,460,012 | | $3,176,705 | $558,908 | $2,324,949 | $215,736 | $77,111 | 1,171,138 | 746,876,199 | | |

| Line | Class / Schedule | Description | Forecast 2019 KWH (1) | Offset Rate (2) | Total Projected Revenues (3) (1)x(2) | Projected Revenues by ECAC Factor: Production Demand (4) 18% | Production Energy (5) 73% | Transmission Demand (6) 7% | Transmission Energy (7) 2% | Effective kW[1] (8) | Effective kWh[1] (9) | Projected ECAC: Demand Rate per kW (10) [(4)+(6)]/(8) | Energy Rate per kWh (11) [(5)+(7)]/(9)[2] | Total ECAC Adjustment Deferred plus Projected: Demand Rate per kW (12) Sum of (10) | Energy Rate per kWh (13) Sum of (11) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 22 | D/DS-8/DM-9 | Residential Service | 369,549,673 | $0.02515 | $9,294,174 | $1,635,214 | $6,802,169 | $631,185 | $225,606 | | 369,233,274 | | 2.517 ¢ | | 2.942 ¢ |
| 23 | A-25 | Small General Service - < 20 kW | 51,917,789 | $0.02515 | $1,305,732 | $229,730 | $955,632 | $86,675 | $31,695 | | 51,916,281 | | 2.515 ¢ | | 2.940 ¢ |
| 24 | A-32 | Small General Service - 20 kW & Over | 67,115,094 | $0.02515 | $1,687,945 | $296,976 | $1,235,364 | $114,632 | $40,973 | 345,240 | 67,113,000 | $1.19 | 1.902 ¢ | $1.39 | 2.223 ¢ |
| 25 | A-36 | Large General Service - 100 kW & Over | 80,107,394 | $0.02515 | $2,014,701 | $354,466 | $1,474,508 | $136,822 | $48,905 | 196,263 | 80,095,236 | $2.50 | 1.902 ¢ | $2.92 | 2.223 ¢ |
| 26 | AT-48 | Large General Service - 500 kW & Over | 81,372,934 | $0.02515 | $2,046,529 | $360,066 | $1,497,803 | $138,984 | $49,677 | 208,998 | 81,121,286 | $2.39 | 1.908 ¢ | $2.79 | 2.230 ¢ |
| 27 | PA-20 | Agricultural Pumping Service | 94,292,504 | $0.02515 | $2,371,456 | $417,233 | $1,735,609 | $161,050 | $57,564 | 420,637 | 94,292,504 | $1.37 | 1.902 ¢ | $1.60 | 2.223 ¢ |
| 28 | | Total Lighting | 3,104,619 | $0.02515 | $78,081 | $13,738 | $57,146 | $5,303 | $1,895 | | 3,104,619 | | 2.515 ¢ | | 2.940 ¢ |
| 29 | | Total | 747,460,012 | | $18,798,619 | $3,307,423 | $13,758,230 | $1,276,650 | $456,316 | 1,171,138 | 746,876,199 | | | | |

Notes:
1 Billing determinants adjusted for primary discounts, employee discounts and easement discounts.
2 Energy rates for all schedules not billed on demand are designed to collect the total ECAC revenues for that schedule.

Application No. 21-08-_____
Exhibit No. PAC/602
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP 2022 ECAC

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GHG Allowance Costs to be Recovered in Rates

CONFIDENTIAL

August 2, 2021

**CONFIDENTIAL**
**Exhibit PAC/602**
**PACIFICORP**
**STATE OF CALIFORNIA**
**GHG Allowance Costs to be Recovered in Rates**
**August 2, 2021**

| Line No. | Description | Forecast | Source |
|---|---|---|---|
| 1 | GHG Allowance Costs | | |
| 2 | 2022 | [redacted] | Confidential Exhibit PAC/202 |
| 3 | Gross up for Franchise Fees and Uncollectibles Expense[1] | | |
| 4 | Subtotal Recorded/Forecast Costs | | |
| 5 | Greenhouse Gas Allowance Costs Sub-balancing Account Under / (Over) Collection | [redacted] | Confidential Exhibit PAC/203 |
| 6 | GHG Allowance Costs to be Recovered in Rates | $ 11,049,309 | line 4 + line 5 |

(1)Factor of 97.977602%

Application No. 21-08-_____
Exhibit No. PAC/603
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP 2022 ECAC

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GHG Allowance Revenue to be Distributed Through the California Climate Credit

August 2, 2021

**Exhibit PAC/603**
**PACIFICORP**
**STATE OF CALIFORNIA**
**GHG Allowance Revenue to be Distributed Through the California Climate Credit**

| Line No. | Description | Forecast for Climate Credit | Source |
|---|---|---|---|
| 1 | GHG Allowance Revenues | | |
| 2 | 2022 | $ (10,661,475) | Exhibit PAC/208 |
| 3 | Gross up for Franchise Fees and Uncollectibles Expense(1) | $ (215,617) | |
| 4 | Subtotal Recorded/Forecast Revenues | $ (10,877,092) | |
| 5 | Greenhouse Gas Allowance Revenue Balancing Account (Under) / Over | $ (2,015,253) | Exhibit PAC/207 |
| 6 | Forecast Expenses - 2022 | | |
| 7 | GHG Outreach and Education Costs | $ 80,000 | Exhibit PAC/303 |
| 8 | GHG Administrative Costs | $ 5,000 | Exhibit PAC/402 |
| 9 | Gross up for Franchise Fees and Uncollectibles Expense(1) | $ 1,719 | |
| 10 | Subtotal Forecast Expenses | $ 86,719 | |
| 11 | Allowance Revenue Approved for Clean Energy or Energy Efficiency Programs (2) | $ 1,066,147 | Line 2 * 10% |
| 12 | Net GHG Allowance Revenues Available for Return | $ (11,739,478) | Line 4 + Line 5 + Line 10 + Line 11 |
| 13 | Summary of California Climate Credit Distribution | | |
| 14 | EITE Customers | $ - | |
| 15 | Small Business Volumetric Return (Forecast) | $ (594,532) | Exhibit PAC/604 |
| 16 | Subtotal Volumetric Return | $ (594,532) | |
| 17 | Total Revenue Available for Residential Climate Credit | $ (11,144,946) | Exhibit PAC/604 |
| 18 | Estimated Number of Households Eligible for Climate Credit | 36,049 | Exhibit PAC/604 |
| 19 | Semi-Annual Residential Climate Credit | $ (154.58) | Exhibit PAC/604 |

(1) Factor of 97.977602%
(2) Commission Decision (D.) 17-12-022 Ordering Paragraph 5 requires PacifiCorp to reserve 10% of the proceeds from the sale of greenhouse gas proceeds for use in the Solar on Multifamily Affordable Housing Program. The set aside started mid-year in 2016 when the company was directed to set aside 5% for half of 2016 and 10% annually thereafter.

Application No. 21-08-_____
Exhibit No. PAC/604
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP 2022 ECAC

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Calculation of Proposed GHG Allowance Costs Surcharge and California Climate Credit Rates

August 2, 2021

**Exhibit PAC/604**
**PACIFICORP**
**STATE OF CALIFORNIA**
**CALCULATION OF PROPOSED GHG ALLOWANCE COSTS SURCHARGE AND CLIMATE CREDIT RATES**

**Forecast 12 Months Ending December 2019**

| | | | | | | 2022 GHG Allowance Costs Surcharge | | | 2022 Climate Credit | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line No. | Description | Sch. | No. of Customers[1] | KWH | Present Revenues | Cost Allocation | Costs | Rate ¢/kWh | 2022 Asst. Factor[2] | Credit Rate | Revenue Distribution | |
| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | |
| | **Residential** | | | | | | | | | | | |
| 1 | Residential Service | D/DL-6 | 35,838 | 368,139,171 | $51,491,651 | | $5,769,373 | | | | ($11,079,714) | |
| 2 | Multi-Family - Master Metered | DM-9 | 28 | 166,767 | $22,021 | | $2,614 | | | | ($8,656) | |
| 3 | Multi-Family - Submetered | DS-8 | 183 | 1,243,740 | $144,333 | | $19,492 | | | | ($56,576) | |
| 4 | **Total Residential** | | 36,049 | 369,549,678 | $51,658,005 | 52.39% | $5,791,478 | 1.567 | | *$ (309.16)* | ($11,144,946) | *annual amount* |
| | | | | | | | | | | **$ (154.58)** | | **semi-annually, per customer** |
| | **Commercial & Industrial** | | | | | | | | | | | |
| 5 | General Service - < 20 kW | A-25 | 7,131 | 51,917,789 | $8,682,837 | 8.81% | $973,450 | 1.875 | 50% | -0.938 | ($486,989) | ¢/kWh |
| 6 | General Service - 20 kW & Over | A-32 | 1,125 | 67,115,094 | $9,240,772 | 9.37% | $1,036,001 | 1.544 | | | | |
| 7 | General Service - 100 kW & Over | A-36 | 191 | 80,107,394 | $8,926,736 | 9.05% | $1,000,794 | 1.249 | | | | |
| 8 | Large General Service - 500 kW & Over | AT-48 | 19 | 81,372,934 | $7,239,603 | 7.34% | $811,646 | 0.997 | | | | |
| 9 | Agricultural Pumping Service - Under 20 kW | PA-20 | 1,002 | 14,833,487 | $12,197,124 | 12.37% | $1,367,443 | 1.450 | 50% | -0.725 | ($107,543) | ¢/kWh |
| 10 | Agricultural Pumping Service - Over 20 kW | PA-20 | 1,024 | 79,459,017 | | | | | | | | |
| 11 | **Total Commercial & Industrial** | | 10,491 | 374,805,715 | $46,287,073 | | $5,189,333 | | | | ($594,532) | |
| | **Lighting** | | | | | | | | | | | |
| 12 | Outdoor Area Lighting Service | OL-15 | 760 | 913,538 | $217,305 | 0.22% | $24,362 | 2.667 | | | | |
| 13 | Airway & Athletic Lighting | OL-42 | 36 | 154,197 | $29,557 | 0.03% | $3,314 | 2.149 | | | | |
| 14 | Street Lighting, Utility Owned | LS-51 | 78 | 845,623 | $235,151 | 0.24% | $26,363 | 3.118 | | | | |
| 15 | Street Lighting, Cust. Owned Energy Only | LS-53 | 105 | 1,138,821 | $163,661 | 0.17% | $18,348 | 1.611 | | | | |
| 16 | Street Lighting, Customer Owned | LS-58 | 20 | 52,440 | $8,967 | 0.01% | $1,005 | 1.917 | | | | |
| 17 | **Total Lighting** | | 999 | 3,104,619 | $654,641 | | $73,393 | | | | | |
| 18 | **Total Sales to Ultimate Consumers** | | 47,539 | 747,460,012 | $98,599,719 | | $11,054,204 | | | | ($11,739,478) | |
| 19 | **Total AGA** | | | | $194,473 | | | | | | | |
| 20 | **Total Employee Discount** | | 87 | 1,249,540 | ($43,433) | | ($4,895) | | | | | |
| 21 | **Total Sales** (inc. AGA and Employee Discount) | | 47,539 | 747,460,012 | $98,750,759 | | $11,049,309 | | | | ($11,739,478) | |

Notes:

1 Customer counts for Schedules DM-9 and DS-8 adjusted to reflect submeter and tenant counts.

2 Based on the Small Business Assistance Factor shown in Table 2 of Appendix 2 of D.13-12-C02.

Application No. 21-08-_____
Exhibit No. PAC/605
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP 2022 ECAC

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Commission Template D-1 – Annual Allowance Revenue Receipts and Customer Returns

CONFIDENTIAL

August 2, 2021

**CONFIDENTIAL**
**Exhibit PAC/605**
**PACIFICORP**
**STATE OF CALIFORNIA**
**Commission Template D-1**
**Annual Allowance Revenue Receipts and Customer Returns**
**August 2, 2021**

| Line | Description | 2013 Forecast | 2013 Recorded | 2014 Forecast | 2014 Recorded | 2015 Forecast | 2015 Recorded | 2016 Forecast | 2016 Recorded | 20 Forecast |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **Proxy GHG Price ($/MT)** | N/A | N/A | N/A | N/A | $ 12.26 | N/A | $ 13.08 | N/A | $ 13.05 |
| 2 | **Allocated Allowances (MT)** | 723,725 | 723,726 | 728,106 | 728,106 | 730,526 | 730,528 | 737,440 | 737,440 | 745,624 |
| 3 | **Revenues** | | | | | | | | | |
| 4 | Prior Balance | N/A | N/A | (9,045,316) | (9,106,055) | (2,668,895) | (3,219,781) | (1,373,502) | (1,190,504) | 478,475 |
| 5 | Allowance Revenue | (9,096,948) | (9,096,948) | [redacted] | (8,518,840) | (8,956,249) | (9,085,917) | (9,545,715) | (9,387,611) | (9,730,393) |
| 6 | Interest | (6,868) | (10,510) | [redacted] | (6,331) | - | 224 | | 4,365 | |
| 7 | Franchise Fees and Uncollectibles | - | - | [redacted] | (319,722) | (245,001) | (164,746) | (174,900) | (170,141) | (176,436) |
| 8 | **Subtotal Revenues** | (9,103,816) | (9,107,458) | [redacted] | (17,950,948) | (11,870,145) | (12,470,220) | (11,694,118) | (10,743,892) | (9,428,354) |
| 9 | **Expenses** | | | | | | | | | |
| 10 | Outreach and Administrative Expenses | 58,500 | 1,403 | 110,000 | 57,941 | 115,000 | 66,328 | 87,500 | 87,672 | 92,000 |
| 11 | Franchise Fees and Uncollectibles | - | - | - | - | - | 1,203 | 1,587 | 1,590 | 1,668 |
| 12 | Interest | - | - | - | - | - | - | - | | - |
| 13 | **Subtotal Expenses** | 58,500 | 1,403 | 110,000 | 57,941 | 115,000 | 67,531 | 89,087 | 89,262 | 93,668 |
| 14 | **Allowance Revenue Approved for Clean Energy or Energy Efficiency Programs (Note 1)** | - | - | - | - | - | - | - | 469,381 | 973,039 |
| 15 | **Net GHG Revenues (Line 8 + Line 13 + Line 14)** | (9,045,316) | (9,106,055) | [redacted] | (17,893,007) | (11,755,145) | (12,402,689) | (11,605,031) | (10,185,249) | (8,361,647) |
| 16 | **GHG Revenues to be Distributed in Future Years** | - | - | [redacted] | | - | - | - | - | - |
| 17 | **Net GHG Revenues Available for Customers in Forecast Year (Line 15 + Line 16)** | (9,045,316) | (9,106,055) | [redacted] | (17,893,007) | (11,755,145) | (12,402,689) | (11,605,031) | (10,185,249) | (8,361,647) |
| 18 | **GHG Revenue Returned to Eligible Customers** | | | | | | | | | |
| 19 | EITE Customer Return | - | - | [redacted] | - | - | - | - | | - |
| 20 | Small Business Volumetric Return | - | - | [redacted] | 864,015 | 1,382,690 | 1,211,183 | 1,053,331 | 961,468 | 496,448 |
| 21 | Residential Volumetric Return | - | - | [redacted] | - | - | - | - | | - |
| 22 | **Subtotal EITE + Volumetric Returns** | - | - | [redacted] | 864,015 | 1,382,690 | 1,211,183 | 1,053,331 | 961,468 | 496,448 |
| 23 | **Number of Households Eligible for the California Climate Credit** | - | - | [redacted] | 35,523 | 36,774 | 35,457 | 36,774 | 35,670 | 36,774 |
| 24 | **Per-Household Semi-Annual Climate Credit (0.5 x (Line 17 + 22) ÷ Line 23)** | N/A | N/A | 194.37 | 194.37 | 141.03 | 141.03 | 143.47 | 143.47 | 106.94 |
| 25 | **Revenue Distributed for the Climate Credit (2 x Line 23 x Line 24)** | - | - | [redacted] | 13,809,211 | 10,372,455 | 10,001,001 | 10,551,700 | 10,235,150 | 7,865,198 |
| 26 | **Total Revenue Distributed** | | | | 14,673,226 | | 11,212,185 | | 11,196,618 | |
| 27 | **Revenue Balance** | N/A | (9,106,055) | N/A | (3,219,781) | N/A | (1,190,504) | N/A | 1,011,368 | N/A |

Note 1: Commission Decision (D.) 17-12-022 Ordering Paragraph 5 requires PacifiCorp to reserve 10% of the proceeds from the sale of greenhouse gas proceeds for use in the Solar on Multifamily Affordable Housing Program. The set aside started mid-year in 2016 when the company was directed to set aside 5% for half of 2016 and 10% annually thereafter. In 2020 set aside was cut to half for the six months (January through June 2020) that had been approved at the time of the 2020 ratesetting in D.20-05-011. Per D.20-04-012, the remaining half of the setaside for July through December has been approved and is to be set aside from 2021 proceeds.

CONFIDENTIAL INFORMATION

**CONFIDENTIAL**
**Exhibit PAC/605**
**PACIFICORP**
**STATE OF CALIFORNIA**
**Commission Template D-1**
**Annual Allowance Revenue Receipts and Customer Returns**
**August 2, 2021**

| Line | Description | 17 Recorded |
|---|---|---|
| 1 | **Proxy GHG Price ($/MT)** | N/A |
| 2 | **Allocated Allowances (MT)** | 745,624 |
| 3 | **Revenues** | |
| 4 | Prior Balance | 1,011,368 |
| 5 | Allowance Revenue | (10,681,011) |
| 6 | Interest | 9,052 |
| 7 | Franchise Fees and Uncollectibles | (193,509) |
| 8 | **Subtotal Revenues** | (9,854,099) |
| 9 | **Expenses** | |
| 10 | Outreach and Administrative Expenses | 60,623 |
| 11 | Franchise Fees and Uncollectibles | 1,099 |
| 12 | Interest | - |
| 13 | **Subtotal Expenses** | 61,722 |
| 14 | **Allowance Revenue Approved for Clean Energy or Energy Efficiency Programs (Note 1)** | 1,068,101 |
| 15 | **Net GHG Revenues (Line 8 + Line 13 + Line 14)** | (8,724,276) |
| 16 | **GHG Revenues to be Distributed in Future Years** | - |
| 17 | **Net GHG Revenues Available for Customers in Forecast Year (Line 15 + Line 16)** | (8,724,276) |
| 18 | **GHG Revenue Returned to Eligible Customers** | |
| 19 | EITE Customer Return | |
| 20 | Small Business Volumetric Return | 466,376 |
| 21 | Residential Volumetric Return | |
| 22 | **Subtotal EITE + Volumetric Returns** | 466,376 |
| 23 | **Number of Households Eligible for the California Climate Credit** | 35,752 |
| 24 | **Per-Household Semi-Annual Climate Credit (0.5 x (Line 17 + 22) ÷ Line 23)** | 106.94 |
| 25 | **Revenue Distributed for the Climate Credit (2 x Line 23 x Line 24)** | 7,646,638 |
| 26 | **Total Revenue Distributed** | 8,113,014 |
| 27 | **Revenue Balance** | (611,262) |

Note 1: Commission Decision (D.) 17-12-022 Ordering Paragraph 5 requires PacifiCorp to reserve 10% of the proceeds from the sale of greenhouse gas proceeds for use in the Solar on Multifamily Affordable Housing Program. The set aside started mid-year in 2016 when the company was directed to set aside 5% for half of 2016 and 10% annually thereafter. In 2020 set aside was cut to half for the six months (January through June 2020) that had been approved at the time of the 2020 ratesetting in D.20-05-011. Per D.20-04-012, the remaining half of the setaside for July through December has been approved and is to be set aside from 2021 proceeds.

CONFIDENTIAL INFORMATION

**CONFIDENTIAL**
**Exhibit PAC/605**
**PACIFICORP**
**STATE OF CALIFORNIA**
**Commission Template D-1**
**Annual Allowance Revenue Receipts and Customer Returns**
**August 2, 2021**

| | | 2018 | | 2019 | | 2020 | | 2021 | |
|---|---|---|---|---|---|---|---|---|---|
| Line | Description | Forecast | Recorded | Forecast | Recorded | Forecast | Recorded | Forecast | Recorded |
| 1 | **Proxy GHG Price ($/MT)** | $ 14.12 | N/A | $ 15.95 | N/A | $ 17.83 | N/A | $ 16.47 | N/A |
| 2 | **Allocated Allowances (MT)** | 752,553 | 752,553 | 759,349 | 759,349 | 767,732 | 767,732 | 551,045 | 549,673 |
| 3 | **Revenues** | | | | | | | | |
| 4 | Prior Balance | (199,575) | (611,262) | (995,401) | (1,289,566) | 565,714 | (931,159) | 216,521 | (713,632) |
| 5 | Allowance Revenue | (10,626,048) | (11,216,803) | (12,111,617) | (12,783,641) | (13,688,662) | (13,082,153) | (9,075,711) | (10,116,732) |
| 6 | Interest | | (28,545) | | (55,368) | | (20,477) | | (17,911) |
| 7 | Franchise Fees and Uncollectibles | (192,676) | (203,906) | (244,945) | (259,656) | (276,839) | (264,987) | (183,547) | (204,963) |
| 8 | **Subtotal Revenues** | (11,018,299) | (12,060,515) | (13,351,963) | (14,388,231) | (13,399,787) | (14,298,776) | (9,042,737) | (11,053,237) |
| 9 | **Expenses** | | | | | | | | |
| 10 | Outreach and Administrative Expenses | 90,000 | 70,705 | 79,500 | 72,625 | 80,100 | 79,708 | 85,600 | 85,000 |
| 11 | Franchise Fees and Uncollectibles | 1,632 | 1,282 | 1,608 | 1,469 | 1,620 | 1,612 | 1,731 | 1,719 |
| 12 | Interest | - | - | - | - | - | - | - | - |
| 13 | **Subtotal Expenses** | 91,632 | 71,987 | 81,108 | 74,094 | 81,720 | 81,320 | 87,331 | 86,719 |
| 14 | **Allowance Revenue Approved for Clean Energy or Energy Efficiency Programs (Note 1)** | 1,062,605 | 1,121,680 | 1,211,162 | 1,278,364 | 895,140 | 864,815 | 1,561,679 | 1,665,781 |
| 15 | **Net GHG Revenues (Line 8 + Line 13 + Line 14)** | (9,864,062) | (10,866,848) | (12,059,694) | (13,035,773) | (12,422,927) | (13,352,642) | (7,393,727) | (9,300,738) |
| 16 | **GHG Revenues to be Distributed in Future Years** | - | - | - | - | - | - | - | - |
| 17 | **Net GHG Revenues Available for Customers in Forecast Year (Line 15 + Line 16)** | (9,864,062) | (10,866,848) | (12,059,694) | (13,035,773) | (12,422,927) | (13,352,642) | (7,393,727) | (9,300,738) |
| 18 | **GHG Revenue Returned to Eligible Customers** | | | | | | | | |
| 19 | EITE Customer Return | - | | - | | - | | - | |
| 20 | Small Business Volumetric Return | 531,084 | 480,075 | 547,880 | 562,070 | 366,984 | 468,938 | 409,556 | 403,561 |
| 21 | Residential Volumetric Return | - | | - | | - | | - | |
| 22 | **Subtotal EITE + Volumetric Returns** | 531,084 | 480,075 | 547,880 | 562,070 | 366,984 | 468,938 | 409,556 | 403,561 |
| 23 | **Number of Households Eligible for the California Climate Credit** | 36,774 | 35,844 | 36,049 | 36,145 | 36,049 | 36,389 | 36,049 | 35,401 |
| 24 | **Per-Household Semi-Annual Climate Credit (0.5 x (Line 17 + 22) ÷ Line 23)** | 126.90 | 126.90 | 159.67 | 159.67 | 167.22 | 167.22 | 96.87 | 97.20 |
| 25 | **Revenue Distributed for the Climate Credit (2 x Line 23 x Line 24)** | 9,332,978 | 9,097,207 | 11,511,814 | 11,542,544 | 12,055,943 | 12,170,072 | 6,984,171 | 6,881,924 |
| 26 | **Total Revenue Distributed** | | 9,577,282 | | 12,104,614 | | 12,639,010 | | 7,285,485 |
| 27 | **Revenue Balance** | N/A | (1,289,566) | N/A | (931,159) | N/A | (713,632) | N/A | (2,015,253) |

Note 1: Commission Decision (D.) 17-12-022 Ordering Paragraph 5 requires PacifiCorp to reserve 10% of the proceeds from the sale of greenhouse gas proceeds for use in the Solar on Multifamily Affordable Housing Program. The set aside started mid-year in 2016 when the company was directed to set aside 5% for half of 2016 and 10% annually thereafter. In 2020 set aside was cut to half for the six months (January through June 2020) that had been approved at the time of the 2020 ratesetting in D.20-05-011. Per D.20-04-012, the remaining half of the setaside for July through December has been approved and is to be set aside from 2021 proceeds.

CONFIDENTIAL INFORMATION

**CONFIDENTIAL**
**Exhibit PAC/605**
**PACIFICORP**
**STATE OF CALIFORNIA**
**Commission Template D-1**
**Annual Allowance Revenue Receipts and Customer Returns**
**August 2, 2021**

| Line | Description | 2022 Forecast | 2022 Recorded | Support |
|---|---|---|---|---|
| 1 | **Proxy GHG Price ($/MT)** | $ 19.36 | | Testimony and Exhibits of Mary M. Wiencke PAC/200-209 |
| 2 | **Allocated Allowances (MT)** | 550,696 | | |
| 3 | **Revenues** | | | |
| 4 | Prior Balance | (2,015,253) | | |
| 5 | Allowance Revenue | (10,661,475) | | |
| 6 | Interest | | | |
| 7 | Franchise Fees and Uncollectibles | (215,617) | | |
| 8 | **Subtotal Revenues** | (12,892,345) | | |
| 9 | Expenses | | | Testimony and Exhibits of Ashley Rask & Anthony B. Worthington PAC/300-304 and PAC/400-403 |
| 10 | Outreach and Administrative Expenses | 85,000 | | |
| 11 | Franchise Fees and Uncollectibles | 1,719 | | |
| 12 | Interest | - | | |
| 13 | **Subtotal Expenses** | 86,719 | | |
| 14 | **Allowance Revenue Approved for Clean Energy or Energy Efficiency Programs (Note 1)** | 1,066,147 | | T&E of J.M.R. PAC/600-607 |
| 15 | **Net GHG Revenues (Line 8 + Line 13 + Line 14)** | (11,739,478) | | |
| 16 | **GHG Revenues to be Distributed in Future Years** | - | | |
| 17 | **Net GHG Revenues Available for Customers in Forecast Year (Line 15 + Line 16)** | (11,739,478) | | |
| 18 | **GHG Revenue Returned to Eligible Customers** | | | Testimony and Exhibits of Judith M. Ridenour PAC/600-607 |
| 19 | EITE Customer Return | - | | |
| 20 | Small Business Volumetric Return | 594,532 | | |
| 21 | Residential Volumetric Return | - | | |
| 22 | **Subtotal EITE + Volumetric Returns** | 594,532 | | |
| 23 | **Number of Households Eligible for the California Climate Credit** | 36,049 | | |
| 24 | **Per-Household Semi-Annual Climate Credit (0.5 x (Line 17 + 22) ÷ Line 23)** | 154.58 | | |
| 25 | **Revenue Distributed for the Climate Credit (2 x Line 23 x Line 24)** | 11,144,946 | | |
| 26 | **Total Revenue Distributed** | | | T&E of M.M.W PAC/200-209 |
| 27 | **Revenue Balance** | N/A | | |

Note 1: Commission Decision (D.) 17-12-022 Ordering Paragraph 5 requires PacifiCorp to reserve 10% of the proceeds from the sale of greenhouse gas proceeds for use in the Solar on Multifamily Affordable Housing Program. The set aside started mid-year in 2016 when the company was directed to set aside 5% for half of 2016 and 10% annually thereafter. In 2020 set aside was cut to half for the six months (January through June 2020) that had been approved at the time of the 2020 ratesetting in D.20-05-011. Per D.20-04-012, the remaining half of the setaside for July through December has been approved and is to be set aside from 2021 proceeds.

CONFIDENTIAL INFORMATION

Application No. 21-08-_____
Exhibit No. PAC/606
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP 2022 ECAC

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Commission Template D-4 – Forecast Revenue Requirement and Revenues by Rate Schedule

August 2, 2021

**Exhibit PAC/606**
**PACIFICORP**
**STATE OF CALIFORNIA**
**Commission Template D-4**
**Forecast Revenue Requirement and Revenues by Rate Schedule**

Bundled Customers

| Line | Rate Schedule (A) | Forecast Sales (kWh) (B) | Forecast GHG Revenue Requirement ($) (C) | Rate Impact ($/kWh) (D) | Forecast GHG Revenue ($) (E) |
|---|---|---|---|---|---|
| 1 | D/DL-6/DM-9/DS-8 | 369,549,678 | $5,786,583 | $0.01567 | ($11,144,946) |
| 2 | A-25 | 51,917,789 | $973,450 | $0.01875 | ($486,989) |
| 3 | A-32 | 67,115,094 | $1,036,001 | $0.01544 | |
| 4 | A-36 | 80,107,394 | $1,000,794 | $0.01249 | |
| 5 | AT-48 | 81,372,934 | $811,646 | $0.00997 | |
| 6 | PA-20 | 94,292,504 | $1,367,443 | $0.01450 | ($107,543) |
| 7 | OL-15 | 913,538 | $24,362 | $0.02667 | |
| 8 | OL-42 | 154,197 | $3,314 | $0.02149 | |
| 9 | LS-51 | 845,623 | $26,363 | $0.03118 | |
| 10 | LS-53 | 1,138,821 | $18,348 | $0.01611 | |
| 11 | LS-58 | 52,440 | $1,005 | $0.01917 | |
| 12 | Total | 747,460,012 | $11,049,309 | | ($11,739,478) |

Note: This template does not include columns F through I as PacifiCorp does not have any unbundled customers

Application No. 21-08-_____
Exhibit No. PAC/607
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP 2022 ECAC

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Effects of Proposed Rate Change Distributed by Rate Schedule

August 2, 2021

**PACIFICORP**
**STATE OF CALIFORNIA**
**ESTIMATED EFFECTS OF PROPOSED RATE CHANGE**
**DISTRIBUTED BY RATE SCHEDULE**
**Forecast 12 Months Ending December 2019**

| Line No. | Description (1) | Pres. Sch. (2) | No. of Customers (3) | KWH (4) | Present Revenues: Base Revenue (5) | Present Revenues: ECAC (6) | Present Revenues: Base with ECAC (7) (5)+(6) | Present Revenues: Adders[1] (8) | Present Revenues: Net Revenue (9) (7)+(8) | Proposed Revenues: Base Revenue (10) | Proposed Revenues: ECAC (11) | Proposed Revenues: Base with ECAC (12) (10)+(11) | Proposed Revenues: Adders[1] (13) | Proposed Revenues: Net Revenue (14) (12)+(13) | Proposed Change: Revenue (15) (12)-(7) | Proposed Change: Percent (16) (15)/(7) | Net Proposed Change: Revenue (17) (14)-(9) | Net Proposed Change: Percent (18) (17)/(9) | Line No. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Residential** | | | | | | | | | | | | | | | | | | |
| 1 | Residential Service | D/DL-6 | 35,838 | 368,139,171 | $40,727 379 | $10,764,272 | $51,491,651 | $4,421,306 | $55,912,957 | $40,727,379 | $9,265,961 | $49,993,340 | $5,021,365 | $55,014,705 | ($1,498,311) | -2.9% | ($898,252) | -1.6% | 1 |
| 2 | Multi-Family - Master Metered | DM-9 | 7 | 166,767 | $17 145 | $4,876 | $22,021 | $2,002 | $24,023 | $17,145 | $4,198 | $21,343 | $2,274 | $23,617 | ($678) | -3.1% | ($406) | -1.7% | 2 |
| 3 | Multi-Family - Submetered | DS-8 | 16 | 1,243,740 | $107 966 | $36,367 | $144,333 | $14,938 | $159,271 | $107,966 | $31,305 | $139,271 | $16,965 | $156,236 | ($5,062) | -3.5% | ($3,035) | -1.9% | 3 |
| 4 | **Total Residential** | | 35,861 | 369,549,678 | $40,852 490 | $10,805,515 | $51,658,005 | $4,438,246 | $56,096,251 | $40,852,490 | $9,301,464 | $50,153,954 | $5,040,604 | $55,194,558 | ($1,504,051) | -2.9% | ($901,693) | -1.6% | 4 |
| | **Commercial & Industrial** | | | | | | | | | | | | | | | | | | |
| 5 | General Service - < 20 kW | A-25 | 7,131 | 51,917,789 | $7,166 362 | $1,516,475 | $8,682,837 | $667,124 | $9,349,961 | $7,166,362 | $1,305,694 | $8,472,056 | $805,223 | $9,277,279 | ($210,781) | -2.4% | ($72,682) | -0.8% | 5 |
| 6 | General Service - 20 kW & Over | A-32 | 1,125 | 67,115,094 | $7,281 814 | $1,958,958 | $9,240,772 | $806,154 | $10,046,926 | $7,281,814 | $1,687,325 | $8,969,139 | $907,959 | $9,877,098 | ($271,633) | -2.9% | ($169,828) | -1.7% | 6 |
| 7 | General Service - 100 kW & Over | A-36 | 191 | 80,107,394 | $6,586 308 | $2,340,428 | $8,926,736 | $893,684 | $9,820,420 | $6,586,308 | $2,014,070 | $8,600,378 | $940,249 | $9,540,627 | ($326,359) | -3.7% | ($279,794) | -2.8% | 7 |
| 8 | Large General Service - 500 kW & Over | AT-48 | 19 | 81,372,934 | $4,863.032 | $2,376,571 | $7,239,603 | $847,655 | $8,087,258 | $4,863,032 | $2,047,300 | $6,910,332 | $826,671 | $7,737,003 | ($329,271) | -4.5% | ($350,255) | -4.3% | 8 |
| 9 | Agricultural Pumping Service | PA-20 | 2,026 | 94,292,504 | $9,441.184 | $2,755,940 | $12,197,124 | $1,101,242 | $13,298,366 | $9,441,184 | $2,369,716 | $11,810,900 | $1,217,885 | $13,028,785 | ($386,225) | -3.2% | ($269,582) | -2.0% | 9 |
| 10 | **Total Commercial & Industrial** | | 10,491 | 374,805,715 | $35,338.700 | $10,948,373 | $46,287,073 | $4,315,859 | $50,602,932 | $35,338,700 | $9,424,104 | $44,762,804 | $4,697,987 | $49,460,791 | ($1,524,269) | -3.3% | ($1,142,141) | -2.3% | 10 |
| | **Lighting** | | | | | | | | | | | | | | | | | | |
| 11 | Outdoor Area Lighting Service | OL-15 | 760 | 913,538 | $190,613 | $26,692 | $217,305 | $15,190 | $232,495 | $190,613 | $22,971 | $213,584 | $20,018 | $233,602 | ($3,721) | -1.7% | $1,107 | 0.5% | 11 |
| 12 | Airway & Athletic Lighting | OL-42 | 36 | 154,197 | $25,053 | $4,504 | $29,557 | $1,950 | $31,507 | $25,053 | $3,878 | $28,931 | $2,501 | $31,432 | ($626) | -2.1% | ($75) | -0.2% | 12 |
| 13 | Street Lighting, Utility Owned | LS-51 | 78 | 845,623 | $210,393 | $24,758 | $235,151 | $17,116 | $252,267 | $210,393 | $21,305 | $231,698 | $22,846 | $254,544 | ($3,453) | -1.5% | $2,277 | 0.9% | 13 |
| 14 | Street Lighting, Cust. Owned Energy Only | LS-53 | 105 | 1,138,821 | $130,338 | $33,323 | $163,661 | $9,794 | $173,455 | $130,338 | $28,679 | $159,017 | $11,852 | $170,869 | ($4,644) | -2.8% | ($2,586) | -1.5% | 14 |
| 15 | Street Lighting, Customer Owned | LS-58 | 20 | 52,440 | $7,436 | $1,531 | $8,967 | $567 | $9,534 | $7,436 | $1,319 | $8,755 | $713 | $9,468 | ($212) | -2.4% | ($66) | -0.7% | 15 |
| 16 | **Total Lighting** | | 999 | 3,104,619 | $563,833 | $90,808 | $654,641 | $44,617 | $699,258 | $563,833 | $78,152 | $641,985 | $57,930 | $699,915 | ($12,656) | -1.9% | $657 | 0.1% | 16 |
| 17 | **Total Sales to Ultimate Consumers** | | 47,351 | 747,460,012 | $76,755,023 | $21,844,696 | $98,599,719 | $8,798,722 | $107,398,441 | $76,755,023 | $18,803,720 | $95,558,743 | $9,796,521 | $105,355,264 | ($3,040,976) | -3.1% | ($2,043,177) | -1.9% | 17 |
| 18 | **Total AGA** | | | | $194,473 | | $194,473 | | $194,473 | $194,473 | | $194,473 | | $194,473 | $0 | 0.0% | $0 | 0.0% | 18 |
| 19 | **Total Employee Discount** | | | | ($34,299) | ($9,134) | ($43,433) | ($3,751) | ($47,184) | ($34,299) | ($7,862) | ($42,161) | ($4,261) | ($46,422) | $1,272 | -2.9% | $762 | -1.6% | 19 |
| 20 | **Total Sales** (inc. AGA and Employee Discount) | | 47,351 | 747,460,012 | $76,915,198 | $21,835,562 | $98,750,759 | $8,794,971 | $107,545,730 | $76,915,198 | $18,795,858 | $95,711,056 | $9,792,260 | $105,503,316 | ($3,039,704) | -3.1% | ($2,042,415) | -1.9% | 20 |

Notes:
1 Total effects of Schedule ECAC-94 Deferred ECAC, Schedule GHG-92 Surcharge to Recover Greenhouse Gas Carbon Pollution Permit Cost, Schedule S-95 Surcharge to Recover Mobilehome Park Utility Upgrade Costs, Schedule S-96 Surcharge to Recover Costs Recorded in Catastrophic Event Memorandum Account, Schedule S-191 Surcharge to Fund Public Purpose Programs, Schedule S-192 Surcharge to Fund Energy Savings Assistance Program, and Schedule S-195 Tax Reform Memorandum Account Adjustment. Excludes the effect of pass through adders.