WASHINGTON CITY POWER

Impact Fee Facility Plan

May 2024

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Table of Contents

SECTION I GENERAL

Introduction

Intermountain Consumer Professional Engineers, Inc. (“ICPE”) performed studies and analyses for Washington City Power (“WCP”) to update their 2019 Electrical Power Capital Facilities Plan and Impact Fee Facilities Plan.

ICPE utilized load predictions in the studies that were developed using recent load data provided by WCP and load trends observed in Washington City over the past several years. The future loads used in the studies are predictions and do not reflect actual values which prevents ICPE from guaranteeing or assuring that the recommendations reflect actual events that will occur in the future. However, it is believed that all predictions and observations used in the study are reasonable and appropriate for the purpose of the Capital Facilities Plan and Impact Fee Facilities Plan.

Impact Fees - General

Impact fees are generally used by cities to fund infrastructure projects necessary to provide services to new developments within the city’s boundary. The new development should bear the additional or incremental capital cost for the services, existing residents who do not benefit from the new development should not bear the costs for services to the new development. Impact fees are not intended for operating expenses or for corrections to existing deficiencies in the services presently being provided by a city. Impact fees are based on anticipated new load increase to the electrical system due to the new developments. The improvements outlined in the plans are required to maintain the present level of service to both new and existing customers.

Impact Fees - Utah

In Utah, impact fees are governed by state statute, specifically U.C.A. 1953 § 11-36a-102. The Statute requires that each governmental agency that imposes an impact fee shall (1) prepare an Impact Fee Facilities Plan (§ 11-36a-301), (2) perform an Impact Fee Analysis (§ 11-36a-303), (3) calculate the Impact Fee(s) (§ 11-36a-305) and (4) certify the Impact Fee Facilities Plan (§ 11-36a-306).

As stated in the Statute, the “Impact Fee Facilities Plan (“IFFP”) shall identify (a) demands placed upon existing public facilities by new development activity; and (b) the proposed means by which the political subdivision will meet those demands.” The IFFP shall also consider all revenue sources, including impact fees, used to finance impacts on system improvements. This report incorporates the most recent WCP Capital Facilities Plan ("CFP"), dated April 2024. In general, the CFP outlines all projects necessary to maintain electrical service to existing customers and the IFFP outlines fees for the improvements necessary to provide service to new developments and customers. Projects identified in the CFP may be due to the correction of an existing deficiency or improvement necessary to maintain reliability and are not included in the IFFP.

The Utah Statute requires the governmental agency that imposes an impact fee to perform an analysis of the impact fee and document the results. The agency is also required to provide a summary document of the analysis that can be understood by a layman. The estimated impacts on the existing electrical system due to the new development are to be included in the Impact Fee Analysis (IFA) along with the costs associated with addressing the impacts. The IFA is also required to include the costs of existing capacity that will be recouped.

Impact Fee calculations may include the following:

(a) The construction cost.
(b) The cost of acquiring land and material.
(c) The cost for planning, surveying, and engineering fees for services provided to design the construction.
(d) Debt service charges, if the impact fees are used to pay the principal and interest on bonds or other obligations to finance the costs of the construction.

Impact Fee calculations are to be based on local industry standard material and labor estimates. The assumptions used to develop the estimates are to be included in the IFA. The IFFP and the IFA area to be certified by the person or entity that prepared the documents.

Washington City

According to the US Census, Washington City is located in Washington County, Utah. The land area is 32.86 square miles and the estimated population in 2023 was about 33,877 persons. The median resident age is 36.3 years, the average household size is 2.99 persons and the median household income is about $94,655.

Washington City Power was formed in 1987 to serve electricity to Washington City. The service area is north of the Virgin River and within the Washington City limits. The CFP and IFFA plans do not include the south side of the Virgin River which is served by Dixie Power.

Electricity Supply

General

Figure 1 illustrates the three basic components of an electrical system, an electric generator that creates the electricity, a transmission system that carries the electricity to the distribution system; and the distribution system that delivers the electricity to the customer.

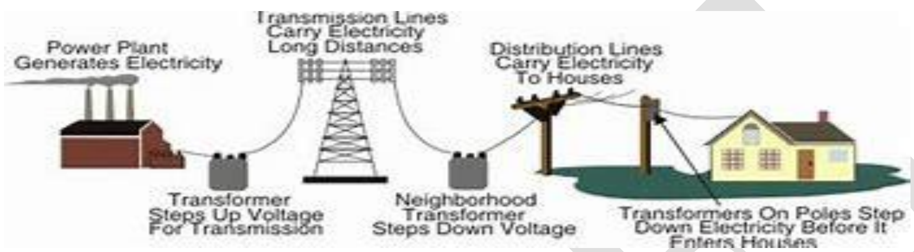

Figure 1

Illustration of a Typical Power Delivery System

Electricity Generation

Electricity is produced by a generator that is powered by a fuel source. The generator can be a steam, hydro, turbine, diesel engine, wind, solar or geothermal. The generated electricity is provided to a utility through purchased power agreements, which can be a firm power agreement (long-term and short-term); unit power (a portion of a specific generating unit) and non-firm (usually short-term). The type and amount of each generating resource that is used by a utility to meet the electrical demand depends on the amount and duration of the demand, the availability of the generating units and the cost of the electricity from the generating units. To meet the hourly demand for electricity, each available generating resource is evaluated according to its availability, capacity and operating cost and then dispatched accordingly to meet the demand for electricity in each hour of the day.

The utility's peak demand is the highest demand for electricity in any one hour. It is during these peak hours that a utility will use multiple generating resources including its own generating resources.

Electricity Transmission

The electricity leaving the generator is stepped up to a higher voltage by a transformer and delivered to the transmission system. The transmission system consists of transmission power poles or towers, conductors, substations and other equipment necessary to deliver electricity from the generators to the utility.

Transmission of electricity to Washington City Power is through the Utah Associated Municipal Power Systems (UAMPS) transmission system. UAMPS receives electricity through Rocky Mountain Power's transmission system.

Electricity Distribution

Electricity distribution is the final stage in the delivery of electricity to customers. An electricity distribution system receives electricity from the transmission system and delivers it to consumers. A typical electric distribution system includes medium-voltage (69 kV & 12.47 kV) power lines, substations, transformers, service drops and metering. The distribution system begins where the voltage is stepped down through transformer(s) and ends at the secondary service point at the customer's meter. Distribution circuits begin at the low-voltage side of the transformer located in the City's substation. Conductors for the distribution delivery system are either located overhead on utility poles or buried underground.

Most electric customers are connected to a pole mounted or pad mounted transformer that reduces the distribution voltage to the low voltage used by customers. Each customer has an electrical service connection and a meter.

SECTION II CAPITAL FACILITIES PLAN AND IMPACT FEE FACILITIES PLAN

General

The Impact Fee Facilities Plan identifies the additional electrical load placed on an existing electrical system by new developments, identifies additions or modifications to the existing electrical system necessary to meet the increased load and provides costs for the system additions or modifications. The Plan will enable the utility to determine how they will fund the projects necessary to meet the load increase to the system.

The following summarizes the results of the Capital Facilities Plan Update that was completed in April 2024 where load increases were identified, projects were proposed to meet the load increase and costs were provided for the proposed projects.

Historical Population and Load Growth

According to the U.S. Census Bureau, the Washington City's population in 2020 was approximately 27,993. The population grew to 33,877 by 2023 for an approximate 20% increase in population over three years. The following table is a summary of the population growth since 1960.

Table 2-1
Washington City Historical Population

Historical population		
Census	**Pop.**	**%±**
1960	445	2.3%
1970	750	68.5%
1980	3,092	312.3%
1990	4,198	35.8%
2000	8,186	95.0%
2010	18,761	129.2%
2020	27,993	49.2%
Est. 2023	33,877	21.0%

Washington City experienced a high growth rate between 1980 and 1990 and between 1990 and 2010. However the electrical load during these periods did not increase as significantly as the population. The annual historical load growth since 1987 is shown in Table 2-2.

Table 2-2
Washington City
Electrical Load History

	PEAK kW			
Year	**Summer Peak**	**% Growth (Summer)**	**Winter Peak**	**% Growth (Winter)**
1987	3,639		6,498	
1988	3,840	5.52%	6,146	-5.42%
1989	4,360	13.54%	6,851	11.47%
1990	4,514	3.53%	6,520	-4.83%
1991	4,433	-1.79%	6,500	-0.31%
1992	5,121	15.52%	5,616	-13.60%
1993	5,615	9.65%	6,083	8.32%
1994	6,514	16.01%	6,268	3.04%
1995	6,984	7.22%	6,376	1.72%
1996	8,112	16.15%	6,436	0.94%
1997	8,590	5.89%	6,665	3.56%
1998	9,883	15.05%	6,410	-3.83%
1999	10,646	7.72%	7,154	11.61%
2000	11,956	12.31%	6,976	-2.49%
2001	14,490	21.19%	8,144	16.74%
2002	15,638	7.92%	8,930	9.65%
2003	17,782	13.71%	8,714	-2.42%
2004	19,840	11.57%	9,716	11.50%
2005	23,971	20.82%	11,302	16.32%
2006	25,093	4.68%	12,966	14.72%
2007	28,542	13.74%	14,854	14.56%
2008	27,852	-2.42%	15,216	2.44%
2009	28,176	1.16%	14,374	-5.53%
2010	29,005	2.94%	14,731	2.48%
2011	29,035	0.10%	14,332	-2.71%
2012	31,518	8.55%	15,332	6.98%
2013	32,117	1.90%	16,614	8.36%
2014	31,714	-1.25%	15,377	-7.45%
2015	34,025	7.29%	14,893	-3.15%
2016	36,134	6.20%	14,945	0.35%
2017	37,943	5.01%	14,906	-0.26%
2018	38,494	1.45%	16,183	8.57%
2019	40,414	4.99%	16,777	3.67%
2020	45,665	12.99%	17,890	6.68%
2021	51,708	13.23%	18,440	3.07%
2022	51,028	-1.32%	18,990	2.98%
2023	52,511	2.91%		

Electric Infrastructure and Future Needs

Transmission

It is proposed to install Grapevine substation by approximately 2025. Significant load is expected to occur in the area surrounding I-15 Exit 13 and in the Solente area lands. The new substation will be required to serve this load. A new 69 kV transmission line will be required to feed Grapevine substation. It is also proposed to install a new 69 kV tie line from the intersection at Main St. and Parkway that feeds the Parkway Substation to the new line feeding Grapevine substation. This will create a 69 kV loop so that both substations can be fed from more than one location in the event of a line outage or for system maintenance. This versatility will enhance the City's ability to operate the electrical system and will improve service reliability to City customers.

Substation & Distribution

Approximately 32 MW of new load is projected over the next ten years in Washington City. Main Street circuits will be heavily impacted since the area currently served by Main Street is projected to grow by 12.3 MW. A significant load for Main Street circuits is expected to occur in the area surrounding I-15 Exit 13 and in the Solente area lands. Additionally, Sienna Hills circuits will need to feed several projects for apartment buildings and hotels that are currently in the planning and construction stages. Without upgrades, the Main Street circuit 202 and Main Street transformer T2 will become overloaded. It is proposed to add a new Grapevine Substation. Three new circuits for the Grapevine substation are proposed. It is proposed to add a third circuit to the Parkway substation to help feed some of the Solente Area.

Approximately 12.9 MW of load is projected for the Solente area lands. A new Grapevine substation, as described above, will help serve this load. Additionally, Parkway circuits will also help serve the new load in this area. Several new distribution lines will be required in the Solente area lands. Three new lines are proposed to be built by Washington City to tie the Solente area lands into existing circuits. The rest of the new lines in the Solente area are proposed to be built by developers as the area is developed.

Level of Service Standards

Consistent with current practice and level of service, Washington City plans, designs and operates its system based on the following criteria:

- Transformer ratings under varying load levels and loading conditions remain below their base rating.
- The system is capable of adequately serving load under single contingency (N-1) situations, where "N" is a power system elements such as a transformer or line.
- The system switching required under an N-1 contingency is simplified to ensure that switching orders not become unnecessarily complex.
- Distribution circuit loading remains below 90% of its maximum current rating.
- Primary circuit voltage is kept between 95% and 105% of its nominal value.
- Distribution circuit mains are able to serve additional load under N-1 contingencies.

The above criteria was used to determine Washington City's future facility needs based on the amount of new load placed on the existing electrical system over the study period.

Demands Placed on Existing Facilities

Electrical demand loads on a system are measured in kilowatts (kW) or kilovolt-amperes (kVA) and are indicated as either coincident-peak ("CP") demand or non-coincident peak ("NCP") demand. The system CP demand is the maximum demand for the entire system measured at a point in time where the sum of all demands on the system is the highest for the system as a whole. The NCP demand is the sum of the maximum demands of individual customers or customer classes such as residential, commercial, industrial, measured for a period of time. The CP demand represents the combined loads across all customer classes measured at the system level where the NCP demand represents the total demand the system would be subject to if all customer classes peaked at the same time. The CP demand is usually lower than the NCP demand. For Impact Fees, CP represents the demand placed on the existing system as a whole, while NCP reflects the maximum demand placed on local facilities by individual customer classes. The CP demand is normally the demand that a utility plans for when sizing facilities that will be used to meet future growth on the system. However, each individual piece of equipment must be able to support its own individual peak demand even if that demand does not occur at the same time as the system's CP.

Washington City's projected CP demand between 2023 and 2032 are shown in Table 2-3. The System CP Demands for the planning period (2023 – 2032) were developed by ICPE.

Table 2-3
Summary of CP Demands
For the Period 2023 through 2033

Description	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total System CP Demands (kW)	52,511	54,882	58,449	62,230	66,073	69,996	73,921	77,355	80,345	83,279

System Modeling for the CFP/IFFP

The recently CFP completed contains results of load flow analysis of the Washington City electrical system. The system load flows provide insight on substation transformer loading, distribution circuit loading, and system voltage drop. The study includes analyzing N-1 outage conditions. An N-1 outage condition is the loss of a major system component such as loss of a substation transformer or loss of a main line section. The existing substations that were studied include Staheli, Main Street, Coral Canyon, Buena Vista, Sienna Hills, and Parkway. Seventeen existing 12.47 kV circuits were studied. The CFP proposes changes to circuit boundaries, the addition of one new substation and the addition of four new circuits.

To perform load flow analysis a system computer model was developed. System model development and analysis were performed on Paladin DesignBase 4.0 software. System modeling data was developed from data provided by Washington City. System load was modeled based on 2022 peak values since they were available at the time. The actual 2023 peak value is close to the projected 2023 peak value. Circuit models are based on the assumption that provided circuit maps and data (conductor sizes, circuit configurations, line lengths, etc.) are reflective of actual field conditions.

Model Results

The following System Improvement Summary from the CFP details the anticipated projects and estimated expenditures necessary to sustain the projected growth rate for Washington City's electrical system for the next 10 years. There is greater confidence in projecting requirements for 2 to 3 years than there is for a 10-year or longer outlook. However it is necessary to forecast future projects due to the magnitude (and cost) of the modifications necessary. Also substation and transmission line projects can take significant time from start to finish due to material lead times and permitting requirements. Substation, distribution, and transmission line requirements need to be addressed to meet future needs of the City in a timely fashion.

The proposed projects will provide a method for Washington City to plan and budget for the facilities necessary to serve the anticipated electrical load growth. Existing electrical facilities as well as new facilities will be used to meet projected load levels. Table 2-4 is a summary of the recommended projects, timing and costs. Detailed cost estimates for the various projects can be found in the appendix of the CFP. Costs shown are based on present 2024 project material and labor pricing.

Table 2-4

Summary of CFP Improvement Projects

For the Period 2024 through 2032*

Project ID	Description	Project Estimated Cost ($) **	Estimated Timeframe	Impact Fee %	Impact Fee Amount ($)	Revenue Funds %	Revenue Funds Amount ($)
25-PR-03	New Circuit 801	350,000.00	2024-2026	100.00%	350,000.00	0.00%	0.00
23-PR-01***	1100 E to 300 E Underbuild Upgrade	231,250.00	2024-2025	40.00%	92,500.00	60.00%	138,750.00
25-PR-01	New Grapevine Substation	6,239,000.00	2024-2025	100.00%	6,239,000.00	0.00%	0.00
24-PR-02	69kV Line Extension to Grapevine with Circuit 802 Underbuild	1,724,000.00	2024-2025	100.00%	1,724,000.00	0.00%	0.00
25-PR-02	69 kV Line Extension to Grapevine	887,000.00	2024-2025	100.00%	887,000.00	0.00%	0.00
23-PR-02	New Circuit 803	669,000.00	2029-2030	100.00%	669,000.00	0.00%	0.00
	Circuit 601/803 to Circuit 402 750 Tie	200,000.00	2024-2025	100.00%	200,000.00	0.00%	0.00
21-PR-06	Circuit 102 to Circuit 603 Tie	478,000.00	2026-2027	100.00%	478,000.00	0.00%	0.00
23-PR-03	Circuit 302 to Circuit 303 Tie	760,000.00	2031-2032	100.00%	760,000.00	0.00%	0.00
	TOTALS	11,538,250.00			11,399,500.00		138,750.00

* Note: Project timing will vary based on actual load growth amount and location.

** Values have been rounded.

*** Project identified in previous CFP and is 75% completed.

IFFP Capital Projects and Costs

As previously mentioned, the costs for the above projects are estimated in 2024 dollars. As with most capital facilities plans, the majority of these projects are scheduled to occur in the earlier planning windows. However, growth in demand on the system generally happens in “groups” or “lumps” according to actual commercial and residential development. Actual load growth may be sooner or later than shown based on current economic and development levels. Projects shown in the IFFP may be delayed or accelerated based on actual load growth locations and timing.

Certification of the IFFP

I certify that the attached Impact Fee Facilities Plan:

1. includes only the costs of public facilities that are:
    a. allowed under the Impact Fees Act; and
    b. actually incurred; or
    c. projected to be incurred or encumbered within six years after the day on which each impact fee is paid;
2. does not include:
    a. costs of operation and maintenance of public facilities;
    b. costs for qualifying public facilities that will raise the level of service for facilities, through impact fees, above the level of service that is supported by existing residents;
    c. an expense for overhead, unless the expense is calculated pursuant to a methodology that is consistent with generally accepted cost accounting practices and the methodological standards set forth by the federal Office of Management and Budget for federal grant reimbursement;

CERTIFIED BY:

Signature: Mac Fillingim

Name: Mac Fillingim

Title: ICPE, Senior Engineer

Date: May, 2024

June 2024

Project Meeting Overview Report

CARBON FREE POWER PROJECT (CFPP)

1. Discussed in Executive Session:
   a. Project wind down status, timeline and Department of Energy interactions.
2. Guest Speaker:
   a. Chris Colbert, Chairman and CEO of Elementl Power, discussed what Elementl is, the company's mission and the development of new nuclear.

CENTRAL-ST. GEORGE PROJECT

1. Discussed the proposed JOA and ITS revisions including PacifiCorp status on the existing JOA & ITS Agreements, the new PacifiCorp proposal for Joint Ownership & Operations Agreement (JOOA) and staff recommendation to consider the JOOA.
2. Discussed the Asset Audit including deliverables for ROW Discovery Project and the process of receiving proposals.
3. Tabled Budget Amendment #3 for next month's meetings to receive more Asset Audit proposals.
4. Discussed BES Exemption update including the start of the assessment from WECC.
5. Discussed the Operations Report including substation reports for the month of May.

COLORADO RIVER STORAGE PROJECT (CRSP)

1. Discussed in Executive Session:
   a. CRSP and CREDA report including hydrology, SEIS, Renewable Energy Credits (RECs) and Olmsted & Provo River Contracts.
2. Discussed the Operations Report including output for each resource for the month of May.

FIRM POWER SUPPLY PROJECT

1. **Approved the Transmission Rate Budget Amendment #4.**
2. Discussed in Executive Session:
    a. Steel 1A & 1B Project including Commercial Operation Dates (COD), status updates and details on the ribbon-cutting ceremony that took place in May.
    b. Red Mesa Tapaha Project including the current status of the project and next steps.
    c. Red Mesa outage update including transmission redirect and outages.
    d. Prepay analysis update including current status, forecasted UAMPS needs and tax certificate “qualified use.”
3. Discussed the Operations Report including output and scheduling from each resource for the month of May.

GOVERNMENT AND PUBLIC AFFAIRS PROJECT (GPA)

1. Discussed Federal & State Legislation including Executive Branch and Congressional Updates:
    a. 2024 presidential election including political topics and debates.
    b. 2024 Utah elections including Primary Election for U.S. Senate and Governor.

HORSE BUTTE PROJECT (HBW)

1. **Approved the Transmission Rate Budget Amendment #4.**
2. Discussed in Executive Session:
    a. RAS Study from Bonneville Power update including summary, current status and next steps.
    b. HBW expansion including current status and next steps.
3. Discussed plant operations including plant maintenance/upgrades, photos of the site and site updates.
4. Discussed the Operations Report including production output for the month of May.

HUNTER PROJECT

1. **Approved the Transmission Rate Budget Amendment #4.**
2. Discussed June 2024 operations strategy including Hunter summer dispatch, soft market and capitalizing on soft market.
3. Discussed the Operations Report including plant scheduled output for the month of May.

INTERMOUNTAIN POWER PROJECT (IPP)

1. **Approved the Transmission Rate Budget Amendment #4.**
2. Discussed fuel settlement for IPP Renewed including possible market participation, settlement process, settlement methodologies, benefits and next steps.
3. **Approved the IPP renewed settlements process and moving forward with the actualized methodology, as discussed.**
4. Discussed the Operations Report including scheduled output for the month of May.

MEMBER SERVICES PROJECT

1. **Approved resolution regarding the Payson Generation Project, authorizing the execution of the Procurement and Construction Agreement and the Capacity Purchase Agreement, authorizing the issuance of Member Services Project Revenue Bonds (Payson City Generation Project), authorizing and directing the officers and management of UAMPS to take all other actions necessary in connection therewith; and related matters.**
2. Discussed AMI RFP update including the AMI Taskforce, vendor responses and next steps.
3. Discussed OSHA training including annual renewal and HSI to schedule a demo for members.

NEBO PROJECT (PAYSON)

1. **Approved the Transmission Rate Budget Amendment #4.**
2. Discussed in Executive Session:

a. Plant operation including May statistics, operational item highlights, plant maintenance/safety highlights, regulatory items and plant water updates.

b. Environmental Audit including tri-annual environmental review.

c. UAMPS Hedging Policy including current term deal, example hedging percentages, UAMPS potential hedge values and next steps.

3. Discussed the Operations Report for the month of May including Nebo energy breakdown and Nebo sales margins.

POOL PROJECT

1. **Approved the Transmission Rate Budget Amendment #4.**
2. Discussed the Operations Report for the month of May including load peak and energy, along with Pool information.

RESOURCE PROJECT

1. Discussed in Executive Session:

   a. Geothermal update including project details, the current status of the project and next steps.

   b. Uinta Wind Energy Project including project details, subscription and next steps.

   c. Natural Gas Study including the current status of the project, site control activities and next steps.

   d. Fremont Solar update including the status of the project and next steps.

2. **Approved resolution for Cost Allocation of Natural Gas Study Costs incurred before project formation, as discussed.**

VEYO HEAT RECOVERY PROJECT

1. **Approved the Transmission Rate Budget Amendment #4.**
2. Discussed the Operations Report including scheduling Veyo for the month of May with peak output and tripped/restricted hours.

BOARD OF DIRECTORS MEETING

1. Discussed in Executive Session:
    a. PacifiCorp transmission rate increase including rates in effect, data requests, goals and next steps.
2. **Approved the Transmission Rate Budget Amendment #4.**
3. Discussed the Operations Report:
    a. Natural Gas storage including regional storage, natural gas consumption and future pricing.
    b. Industry News including EDAM developments and PacifiCorp EDAM stakeholder meetings.
    c. Seasonal Outlook including June forecast, a look at the prior month and summer outlook.
    d. PacifiCorp Wildfire Mitigation including Public Safety Power Shutoff (PSPS), including ongoing engagement with PacifiCorp and UAMPS' distributed Communications Support Package.
4. **Approved UAMPS bylaw amendments.**
5. **Approved updated CEO hiring policy with recommended change.**
6. Approved all action items for the Project Meetings.
7. Discussed holding the next board meeting via Zoom on July 17th.

Utah Associated Municipal Power Systems

TALKING POINTS RE: PACIFICORP RATE INCREASE
JUNE 20, 2024

OVERVIEW

UAMPS pays PacifiCorp to use its transmission system to deliver wholesale electric power to UAMPS members. UAMPS charges its members transmission rates for their metered use of the transmission system. Because UAMPS' fiscal year does not align with PacifiCorp's annual formula rate filing, UAMPS projects the amount of the transmission rate increase based on historical experience and known cost increases. For the 2025 fiscal year, UAMPS projected a 2.0% increase in the transmission rate.

Changes to the transmission rate occur annually when PacifiCorp files an update of revenue and costs with FERC, including a true up for the costs projected in the previous year's filing. This update is made according to a formula rate that has been approved by FERC. Because such updates are based on clearly defined inputs and designed to be routine, FERC has allowed PacifiCorp to make its filing on May 15 with the new rate to go into effect on June 1. In the previous 9 years, the change has ranged from 1%-12%.

The inputs to the formula rate include costs relating to O&M, new capital investment, depreciation, revenue requirement, transmission in service and taxes among other items.

Interested parties are allowed to ask PacifiCorp questions about the basis for its formula rate calculation and to challenge the calculation first by notifying PacifiCorp of their concerns and, if PacifiCorp and the interested party are unable to reach an agreement, by filing with FERC. FERC determines whether the formula rate is appropriate based on the written submissions of the parties and may hold a hearing. If FERC determines that PacifiCorp set the rate too high, PacifiCorp must refund any overpayment to transmission customers.

If PacifiCorp seeks to include costs outside of the formula (including "extraordinary property losses") in the transmission rate, it must make a separate filing with FERC and may not include them in the formula rate update. PacifiCorp has not currently classified the wildfire liability costs as "extraordinary property losses," but UAMPS will seek reclassification. Proceedings to include costs in rates that are not included in the formula rate are typically more thorough, and accordingly take more time, than challenges to the formula rate.

PacifiCorp's 2024 formula rate filing seeks a 45% increase to transmission rates effective as of June 1, 2024.

MEMBER IMPACT

Why Such a Large Increase?

- PacifiCorp is attempting to recover its costs to settle third-party liability claims relating to the 2020 Oregon wildfire. Such costs appear to account for approximately half of the increase in transmission rates.
- Another significant driver is from new transmission infrastructure, including sections of the Energy Gateway transmission line that are expected to go into service in 2024.
- UAMPS and other transmission customers are working together with an external consultant to investigate whether there are any other significant drivers worth challenging.

What are the Member Impacts?

- The previous transmission rate was $6.93/MWh. The increase translates to a $2.52/MWh for a new transmission rate of $9.45/MWh.
- Members will see this increase on their June bills, invoiced July 2024.
- UAMPS does not anticipate that this increase will necessitate Members to seek rate increases at the local level; nevertheless, UAMPS will vigorously challenge this unprecedented transmission rate increase to mitigate impacts to the Members.
- UAMPS has provided an updated budget to assist members in identifying respective impacts and is ready to assist any Member that desires further assistance in evaluating specific impacts to the Members.
- Members with internal generating resources subject to the transmission gross-up provisions will see an increase in transmission costs associated with running those generators.
- If FERC determines that the increase was in error, PacifiCorp will be required to refund the overcollection.

What is UAMPS Doing to Mitigate?

- UAMPS will challenge the inclusion of any unwarranted costs, including third-party wildfire liability claims, in transmission rates both through the formula rate process and additional FERC proceedings as appropriate.
- UAMPS will seek an order from FERC recategorizing the accounting for wildfire costs so they will not be included in the formula rate increase. If UAMPS is successful PacifiCorp would have to seek a separate ruling from FERC before including such costs in transmission rates.
- UAMPS can assist members with internal generation in calculating the effect of the increased transmission rate on running their generators.