SIERRA NEVADA REGION

WESTERN AREA POWER ADMINISTRATION

2024 Proposed Rates For the Central Valley Project and California-Oregon Transmission Project

Rate Order No. WAPA-207

Customer Brochure

November 2023

Contact Information

Michelle Williams,
Senior VP and
SN Regional Manager
Telephone: (970) 461-7354
Email: mrwilliams@wapa.gov

Arun Sethi,
SN VP of Power Marketing
Telephone: (916) 353-4452
Email: ASethi@wapa.gov

Autumn Wolfe
SN Rates Manager
Telephone: (916) 353-4686
Email: Wolfe@wapa.gov

Judy Shimek
SN Public Utilities Specialist, Rates
Email: Shimek@wapa.gov

Sierra Nevada Region
Western Area Power Administration
114 Parkshore Drive
Folsom, CA 95630-4710

E-mail Address for Official Comments
Email: SNR-RateCase@wapa.gov

Materials Posted on Website
Rate Case 2024 WAPA 207 – Western Area Power Administration

Contents

List of Tables

INTRODUCTION

This brochure provides information on Western Area Power Administration's (WAPA) proposed firm power, transmission, and ancillary service rate adjustment for the Central Valley Project (CVP) and, California-Oregon Transmission Project (COTP) under Rate Order No. WAPA-207.

Rate Orders WAPA-173 and WAPA-194 are set to expire September 30, 2024, and December 31, 2024, respectively. WAPA-SN needs to adopt new formula rates so WAPA-SN's costs can continue to be recovered. The proposed rates continue the formula-based methodology that includes an annual update to the financial data in the rate formulas. WAPA-SN intends the proposed formula-based rates go into effect October 1, 2024. The charges under the rates will be updated at least annually. The proposed formula rates will remain in effect until September 30, 2029, or until WAPA changes the formula rates through another public rate process pursuant to 10 CFR part 903, whichever occurs first. Because the existing rates are updated annually, using the same formula-based approach, customers should not expect to see their overall costs vary widely in each successive year.

Project Descriptions and Background Information

Central Valley Project

The CVP in California's Central Valley was originally authorized in 1935 and reauthorized in 1937. Historically, the CVP has been authorized and operated as one operationally and financially integrated project. As a result, as subsequent units and features were authorized and constructed, the CVP was reauthorized to include the new units/features as part of the one single integrated multipurpose project. WAPA markets generation from 11 powerplants, consisting of 38 hydroelectric generating units. The generating units have an installed capacity of 2,139 megawatts. The U.S. Bureau of Reclamation (Reclamation) operates the water control and delivery system and all the powerplants except for the San Luis Unit (also known as W.R. Gianelli), which is operated by the State of California for Reclamation.

Under WAPA's Power Marketing Plan, WAPA markets the CVP, a portion of the Pacific Northwest-Pacific Southwest Intertie, and the Washoe Project. The CVP includes 1,363 circuit miles of high-voltage transmission lines and transmission lines from the northern portion of the Pacific Northwest-Pacific Southwest Intertie.

Allocations made through power marketing plans of the CVP govern power sales. Each customer receives a percentage of the output of the CVP net generation, referred to as a Base Resource (BR) allocation. The CVP generation will vary hourly, daily, monthly, and annually because it is subject to hydrological conditions and other constraints that may govern CVP operations. In addition, certain customers also receive additional power products to complement their BR allocations. These additional power products supplement the BR allocation and are provided through custom power contracts.

Washoe Project

The Stampede Dam and Reservoir are located on the Little Truckee River in Sierra County, California, about 11 miles northeast of the town of Truckee. The Washoe Project was designed to improve the regulation of runoff from the Truckee and Carson River system and to provide supplemental irrigation water and drainage, as well as water for municipal, industrial, fishery use, flood protection, fish and wildlife benefits, and recreation.

The power generation is used principally to provide energy for two Federal fish hatcheries: Lahontan National Fish Hatchery and Marble Bluff Fish Hatchery. The Stampede Powerplant has two units with an hourly maximum operating capability of 3,650 kilowatts with an estimated annual generation of 11 million kilowatt-hours annually. The energy generated by the powerplant has a priority reservation for designated project use loads. All remaining energy generation is sold on a non-firm basis, giving priority to preference entities. Energy generated at Stampede depends on the run of the river.

More information on the Washoe Project can be located on the SN rates website at: https://www.wapa.gov/about-wapa/regions/sn/sn-rates/rate-case-2022-wapa-201/

Path 15 Transmission Upgrade

The Path 15 Transmission Upgrade was completed in 2005 to relieve transmission constraints and is crucial to the reliability of power systems in California. WAPA-SN turned over the operational control of WAPA-SN's Path 15 Upgrade to the CAISO. WAPA-SN maintains the lines and is compensated for the Operation and Maintenance work. The CAISO charges for use on the Path 15 Upgrade as part of its rates. WAPA-SN does not charge a separate rate for Path 15 Upgrade. WAPA-SN collects revenues from the CAISO under its agreements with the CAISO. Under Amendment No. 48, the CAISO remits to WAPA-SN, wheeling, congestion, and Congestion Revenue Rights revenues associated with WAPA-SN's rights on the Path 15 Upgrade.[1]

Path 15 is in the southern portion of PG&E's service area and in the middle of the California Independent System Operator's (CAISO) Balancing Authority Area. Path 15 is rated at 3,900 MW and consists of these lines:

Los Banos-Gates, 500kV
Los Banos-Midway, 500kV
Gates-Panoche No. 1, 230 kV
Gates-Panoche No. 2, 230 kV
Gates-Gregg, 230 kV
Gates-McCall, 230 kV

Power Marketing Plans

WAPA-SN markets the net hydropower generation from the Central Valley and Washoe Projects. WAPA-SN's 2025 Power Marketing Plan utilizes the same approach established by the 2004 Power Marketing Plan. The 2004 Power Marketing Plan was

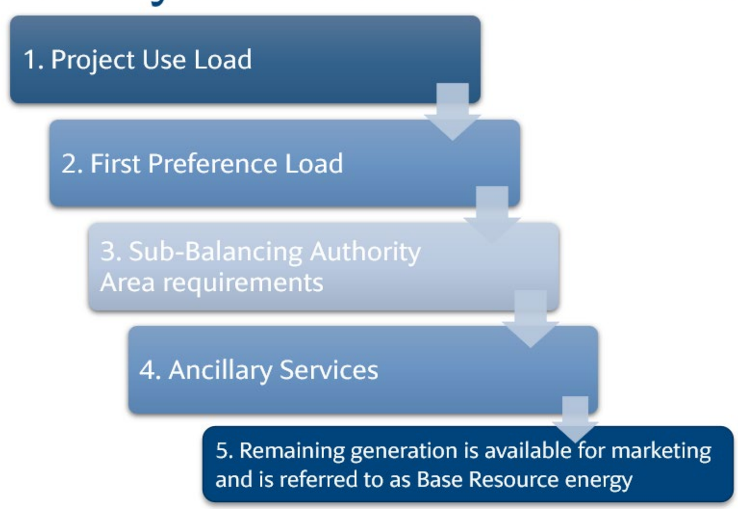
[1] Amendment No. 48 amended CAISO's tariff to provide congestion revenues, wheeling revenues, and firm transmission rights auction revenues to entities other than CAISO's Participating Transmission Owners, if any such entities fund transmission facility upgrades on the CAISO grid. See Federal Energy Regulatory Commission Docket No. ER03-407-000.

published in the Federal Register, (64 FR 24417) on June 25, 1999, and the 2025 Power Marketing Plan was published in the Federal Register, (82 FR 38675) on August 15, 2017.

BR is a fundamental component and the primary power product marketed through the Power Marketing Plan. Under contract, BR customers receive an allocated percentage of the BR. A BR contract details the specifics of how WAPA-SN will provide power to its customers.

The Marketing Plan acknowledges that the BR may vary widely on an hourly, daily, weekly, monthly, and annual basis, depending on hydrological conditions and other constraints that govern CVP operations. CVP generation must be adjusted for Project Use (PU), First Preference (FP) entitlements, maintenance, reserves, transformation losses and certain ancillary services before CVP generation is available for marketing. WAPA-SN intends to provide operating reserves to its customers per the Sub-Balancing Authority Area (SBAA) operator's protocols to support BR, PU, and FP deliveries. During some months, purchases may be required to meet PU and obligations to FP customers, and only a negligible amount, if any, of BR will be available during some hours of such months.

Priority Use of CVP Generation



The Trinity River Division Act (69 Stat. 719) and the New Melones project provisions of the Flood Control Act of 1962 (76 Stat. 1173, 1191-1192), provide that FP of up to 25 percent of the additional energy made available from the CVP power system as a result of the construction of the plants authorized by these Acts, be made available to preference customers in the counties of origin (Trinity, Tuolumne, and Calaveras), for use in those counties. The power costs associated with meeting these requirements are included in the BR rate development discussion.

According to the Power Marketing Plan, WAPA-SN will market BR separately or in combination with Custom Products (CP). "Custom Product" means a combination of products and services, which may be made available by WAPA-SN per customer request. These products could include WAPA-SN acting on behalf of a customer to: (1) purchase CP power, (2) manage a portfolio of power resources, (3) provide scheduling services per Balancing Authority Area (BAA) protocols, and (4) procure ancillary services.

WAPA-SN classified customers who contract for Custom Products into two different customer groups: Full Load Service (FLS) customers or Variable Resource (VR) customers. FLS customers are those who require some additional products and services to meet their full load requirements and who are contracted with WAPA-SN for such service. VR customers schedule their Federal power from WAPA-SN into their own "resource portfolio" to meet their load requirements.

WAPA-SN determined that CVP network transmission service will be provided as a bundled product with the BR. For all other products, such as a CP, separate transmission arrangements must be made by the customer with the appropriate transmission service provider. Customers interested in acquiring transmission service from the CVP system above that provided for BR deliveries will need to apply through WAPA's Open Access Transmission. Tariff (OATT). To the extent possible, if WAPA-SN has sufficient transmission rights, WAPA-SN merchant will use its rights to meet CP transmission requirements. If WAPA-SN merchant does not have transmission rights, separate transmission arrangements need to be made with the appropriate transmission service provider.

OVERVIEW OF PROPOSED FORMULA RATES

The following provides an overview of the proposed formula rates. WAPA-SN is not proposing any changes to existing rate methodologies. The existing formula rates provide sufficient revenue to recover annual costs within the cost recovery criteria set forth in Department of Energy (DOE) Order RA 6120.2. The proposed rates are unchanged from the existing formula rates, which expire on September 30, 2024, and December 31, 2024. WAPA intends the proposed formula rates to go into effect on October 1, 2024. The rates would remain in effect until September 30, 2029, or until superseded through another public rate process pursuant to 10 CFR part 903, whichever occurs first.

Summary of Proposed Rate Schedule Changes

WAPA-SN is not proposing any changes to its existing formula rate methodologies.

A rate process is needed because the existing rate schedules are expiring and WAPA requires new authority to recover project costs beginning October 1, 2024. The proposed rate schedules will set the formula rates in place for a new 5-year period. The proposed rates will continue to provide sufficient revenue to pay all annual costs including interest expense, investments, and aid to irrigation within the allowable periods. The proposed rate schedules take the opportunity to marry language among the rate schedules and to align with WAPA-wide templates. The language is edited to be clearer and more concise.

The following are some proposed changes to the existing rate schedules:

1. In the existing rate schedules, WAPA refers to itself as “Western”. In the proposed rate schedules, “Western” will be changed to “WAPA-SN”. This aligns with WAPA-wide formatting practices.

2. Proposed rate schedules are edited for plain language, and removal of procedures documented elsewhere.

3. Removed examples from rate schedules that are contained within this rate brochure.

4. The existing rate schedule COTP-T3 calculates COTP Point-to-Point Transmission Service rates for <u>three</u> seasons: Summer, Winter, and Spring. Since minimal cost changes occur from season to season, the proposed rate schedule COTP-T4 only has <u>one</u> season.

Power Revenue Requirement and Allocation to Preference Customers

Before the start of each fiscal year (FY), WAPA-SN will calculate and publish an annual Power Revenue Requirement (PRR) to determine the total cost of power. As part of the rate development, WAPA-SN prepares a Power Repayment Study (PRS) each FY to determine if revenue will be sufficient to repay, within the required time periods, all costs assigned to the preference power function. Repayment criteria are based on legislation and applicable policies, including DOE Order RA 6120.2. Generally, the PRR includes operation and maintenance (O&M) expenses, purchased power for PU and FP customers' loads, interest, and other expenses (including any other statutorily required costs or charges), investment repayment, and the Washoe Project annual PRR that remains after project use loads are met. Revenues from project use, transmission, ancillary services, and other services are offset against expenses in the PRR; and the remainder is collected from BR and FP customers. The PRR is reviewed during March of each year; and if such review results in a change of $5 million or more, the PRR is adjusted for the remaining 6-month period. The PRR is an estimate of revenues and costs including investment and repayment projections from the PRS. Any deviation from estimate to actual will increase or decrease annual project repayment. Project repayment is measured over the long term to ensure repayment is met and to maintain rate stability.

The PRR is allocated to WAPA-SN's preference customers, namely, FP customers based on their FP percentages, and the remaining amount to BR customers based on their BR allocation, adjusted for programs, such as, hourly exchange. The Trinity River Division Act of 1955 (69 Stat. 719) and the Flood Control Act of 1962 (76 Stat.1173, 1191-1192) accorded first preference to CVP power to customers in Trinity, Tuolumne, and Calaveras Counties. A BR customer, under the 2004 & 2025 Marketing Plans, is an entity that has executed a BR contract and is allocated a percentage of the BR.

For WAPA-SN to meet the load requirements, beyond delivered BR, for Full Load Service (FLS) customers and Variable Resource (VR) customers, WAPA-SN may make supplemental power (SP) purchases, pursuant to the Custom Product Power (CPP) rate schedule. FLS and VR customers who contract with WAPA-SN for such service will pay all SP costs. FLS customers pay a portfolio management charge pursuant to their contract, whereas VR customers pay a scheduling charge pursuant to the proposed rate schedule.

Sale of Surplus Product Rates

The rates are for the sale of surplus energy and/or capacity products. This includes: (1) Energy, (2) Frequency Response Service, (3) Regulation, (4) Reserves, and (5) Resource Sufficiency. If any surplus products are available, WAPA could make the product(s) available for sale, provided entities enter into separate agreement(s) which would specify the terms of sale(s).

Transmission Revenue Requirements and Rates

At least annually, WAPA will publish the CVP transmission rates for point-to-point and Network Integration Transmission Service (NITS), the COTP and PACI transmission rates and CVP regulation and frequency response service rates. PACI will be a separate rate setting process. WAPA prepares a detailed cost-of-service study to determine the costs, by project, that support the transfer capability of each transmission system and the cost that supports the generation capability of the CVP system. Generally, the costs allocated through the cost-of-service study for the transmission systems include O&M, interest, and depreciation expenses. WAPA's costs for scheduling, system control and dispatch service associated with CVP, COTP, and PACI transmission service are included and recovered through the respective transmission system's Revenue Requirement. Third-party transmission service costs are passed through directly to each requesting customer.

Ancillary Service

In accordance with WAPA's OATT, ancillary services are needed with transmission service to maintain reliability.

Spinning and supplemental reserves are charged the price consistent with the California Independent System Operator's (CAISO) market price plus all costs incurred for the sale of these reserves.

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load within the SBA over an hour or in accordance with approved policies and procedures. Generator Imbalance Service is provided when a difference occurs between the scheduled and actual delivery of energy from an eligible generation resource within the SBA, over an hour, or in accordance with approved policies.

EIM Services

WAPA participates in the Energy Imbalance Market (EIM) as a Transmission Provider within the Balancing Authority of Northern California (BANC) BAA, WAPA is proposing continued formula rate schedules for: (1) EIM Administrative Service, (2) EIM EI Service, and (3) EIM GI Service. In EIM, CAISO economically dispatches energy under its EIM Tariff to meet the imbalances for loads and resources over multiple BAAs. CAISO provides a centralized, automated, and region-wide dispatch for imbalances. The EIM Administrative Services formula rate allows WAPA to pass through administrative costs incurred by WAPA resulting from its participation in EIM as a Transmission Provider. The formula rates and cost allocation for Administrative, EI and GI services would be in effect when WAPA is participating in the EIM, and to the extent WAPA incurs associated settlements during market suspension or contingency.

Proposed Rate Comparison

The Table 1 below compares the existing rates (FY 2022) for Power, Transmission, Ancillary Services, Surplus Products and Energy Imbalance Market current estimated rates (FY 2023) under the proposed formula rate. The differences are not due to change in rate methodology, but attributable solely from updated information.

Table 1 Rates Comparison

Service	Existing 2023	Proposed 2025*	Explanation for Change
Power			
Power Revenue Requirement	$57,460,583	$60,368,802	Forecasted financial and/or operational data. Proposed 2025 rate will be updated August 2023 forecast
Base Resource Revenue Requirement	$51,740,169	$53,610,515	Forecasted financial and/or operational data
First Preference Revenue Requirement	$5,720,414	$6,758,287	Forecasted operational data
First Preference Allocation	9.96%	9.96%	No change
Custom Power Purchase	Pass-through		No change
Variable Resource Scheduling Charge	$42.66		N/A
Transmission Service			
CVP Transmission (Pt-to-Pt) ($/KW-Month)	$1.85	$1.94	Anticipated completion of new assets that support transmission function
CVP Network Integration Transmission Service (NITS) ($/Month)	$2,316,315	$2,664,497	Anticipated completion of new assets that support transmission function
COTP Transmission (Pt-to-Pt) ($/MWh)	$3.61 (Spring) $3.60 (Summer) $3.65 (Winter)	$3.69 (One rate)	2 % inflation
Other Transmission Service			
Transmission of WAPA Power by Others	Pass-through		N/A
Unreserved Use Penalties	200%	200%	No change
Ancillary Service			

Service	Existing 2023	Proposed 2025*	Explanation for Change
Regulation and Frequency Response Service ($/kW-Month)	$5.23	$5.96	Forecasted financial and/or operational data
Other Ancillary Service			
Spinning Reserve Service	Market (CAISO Spin LMP) plus Admin Cost		N/A
Supplemental Reserve Service	Market (CAISO Non-Spin LMP) plus Admin Cost		N/A
Energy Imbalance Service	Financially Settled		N/A
Generator Imbalance Service	Financially Settled		N/A
Surplus Products			
Sale of Surplus Products	Greater of WAPA's Cost or Market rates		N/A
Energy Imbalance Market Service			
EIM Administrative Service Charge	Sub-allocated based on load ratio share		N/A
EIM Energy Imbalance Service	Sub-allocated based on load ratio share		N/A
EIM Generator Imbalance Service	Directly assigned and/or sub-allocated based on load ratio share		N/A

*FY 2025 rates are estimates, the rates effective October 1, 2024, will have updated financial and operation data applied to the formula rates.

RATE HISTORY

Power Revenue Requirement Rate History

Beginning with the 2004 Marketing Plan, effective January 1, 2005, WAPA-SN changed its CVP rate structure to a Power Revenue Requirement methodology. This change was the result of a new marketing approach where customers no longer received a firm product. Customers now receive their percentage share of the hourly daily, weekly, monthly, and yearly net generation allocation output of the CVP. The table below lists the CVP 5-year historical power revenue requirement rates.

Table 2 CVP 5-Year Historical Power Revenue Requirements

Central Valley Project Power Revenue Requirement 5-Year Rate History			
Fiscal Year	Base Resource Revenue Requirement	First Preference Revenue Requirement	Power Revenue Requirement
2019	$70,404,653	$4,303,171	$74,707,824
2020	$65,108,843	$3,665,682	$68,774,525
2021	$66,981,208	$5,777,002	$72,758,210
2022	$61,986,580	$7,814,197	$69,800,777
2023	$51,740,169	$5,720,414	$57,460,583

Transmission Rate History

Below is a five-year history of CVP Transmission Revenue Requirements, Network Integrated Transmission Service (NITS) and Point-to-Point Transmission Rates.

Table 3 CVP 5-Year Transmission Rate History

Central Valley Project Transmission Revenue Requirements and Rates			
Effective Date	TRR	NITS	Point-to-Point Transmission Rate (PtP) $/kW Mo
April 1, 2018	$52,020,050	$36,273,170	$1.88
April 1, 2019	$50,049,808	$34,805,488	$1.82
April 1, 2020	$51,974,051	$35,724,611	$1.94
April 1, 2021	$52,065,898	$36,654,058	$1.84
April 1, 2022	$48,152,002	$29,054,242	$1.76
April 1, 2023 - Current	$49,396,383	$27,795,783	$1.85

POWER REPAYMENT STUDY

The Power Repayment Study (PRS) is prepared annually by WAPA-SN in cooperation with the Reclamation. Historical revenues and expenses are based on WAPA-SN and Reclamation Financial Statements. Power repayment studies are prepared in accordance with authorizing legislation and with Department of Energy (DOE) Order No. RA 6120.2 (Power Marketing Administration Financial Reporting).

The PRS summarizes historic revenues, expenses, and investments to be recovered by the rates. It also estimates income, expenses, and investments for future years. The PRS demonstrates the application of revenues, as well as the annual repayment of power system production and transmission costs, and other costs assigned to power for repayment. Total Federal investment remaining to be repaid over the repayment period or service life is also shown. Revenues, expenses, and investments are entered into the PRS from historical data and future budget estimates. These figures are then used to estimate long-term projections of revenues and expenses.

The PRS is used to assure the adequacy of the existing revenue requirements and rates. It determines if power revenues are sufficient to pay all project costs allocated to power for repayment within the appropriate repayment period. The PRS first applies the revenue to a payment of total annual operating expense, which includes operation and maintenance (O&M), purchased power and transmission, and interest. The revenues are then applied toward investments in the following order: required principal payments (payments at the end of their repayment period), deficits (capitalized expenses and required payments from years when revenues did not cover all expenses), and discretionary principal payments (payments on investments that are not at the end of their repayment period). Discretionary principal payments are normally made first to investments having the highest interest rate.

If the PRS demonstrates that repayment requirements will not be recovered or will be exceeded under the existing rates, WAPA-SN prepares and recommends a plan to meet repayment requirements and maintain rate stability.

Cost Allocation

All O&M costs and the capital costs associated with the CVP are allocated by Reclamation. The costs include WAPA, Reclamation, and Corps project costs that have been integrated with the CVP. A brief overview of Reclamation's cost allocation process follows.

The Separable Cost-Remaining Benefit Method (SCRB) is used as the basic cost allocation methodology. The power related capital costs are first allocated to a total power function. These costs consist of all power facilities' costs plus the power portion of multipurpose, joint costs. The total power costs are then sub-allocated between CVP preference and CVP project use power functions in proportion to the projected usage of CVP resources and facilities by the commercial power users and project use customers. Only preference power costs are those repaid through WAPA's rate-setting process.

CVP Final Cost Allocation Study

On January 14, 2020, Reclamation completed the CVP Final Cost Allocation Study. The purpose of the study is to develop allocation factors for the authorized purposes of the CVP that are used to determine the final repayment obligations for CVP facilities subject to repayment by the year 2030. Using the factors developed in the Final CVP Cost Allocation Study, Reclamation will update the cost allocation for the existing plant-in-service costs on an annual basis. The Final CVP Cost Allocation Study updated outdated factors which had been in use since 1975. Reclamation conducted the final study in consultation with CVP stakeholders and other Federal agencies, including WAPA, USACE and USFWS through coordination on key issues and analyses. The CVP Final Cost Allocation Study can be found on Reclamation's website at: https://www.usbr.gov/mp/cvp/docs/cvp-final-cost-allocation-study-2020.pdf . The results of the study identify a decrease of $32,178,392 in the allocation of capital costs assigned to commercial power for repayment.

Due to the retroactive change in the allocation of capital costs to preference power, a subsequent adjustment was required to interest charged on unpaid capital balances over the life of the project. In fiscal year 2022, WAPA, as the agency responsible for calculating interest on unpaid capital balances for preference power, adjusted interest expense retroactive to the beginning of the project (1944). The total adjustment to interest was $152.3 million. The dollars made available from the reduction to interest expense were reapplied to reduce the power customers CVP repayment obligation.

Repayment Requirements

In general, revenue must be sufficient to recover the following:

1. Annual O&M expenses, purchase power and transmission, other power related service expenses, and interest on investment and deferred expenses.

2. After payment of annual expenses, deferred expenses (deficits) are repaid, starting with the highest interest-bearing deferred expense first, unless an investment has reached the end of its repayment period.

3. After payment of annual expenses and deferred expenses, the Federal investment allocated or assigned to the preference power function must be repaid within the allowable repayment period. Once again, the highest interest-bearing investment is repaid first.

Annual Revenue

Annual Revenue is collected in the year it is incurred. Annual Revenue includes Purchased Power, Other Pass-Through, Other and Project Use. The PRR forecasts future revenue. Table 4 shows the projected annual revenues for October 1, 2025, through September 30, 2029.

Table 4 Projected Future Revenues

Fiscal Year	Project Use	Power	Transmission	Other	Custom Product Power	Total
2025	$30,895,182	$75,733,265	$98,691,022	$68,712,974	$196,053,275	$470,085,718
2026	$31,783,657	$75,733,265	$98,863,033	$70,811,253	$199,974,340	$477,165,548
2027	$32,517,855	$77,248,762	$99,038,484	$72,436,595	$203,973,827	$485,215,523
2028	$33,303,865	$79,525,170	$99,217,444	$73,852,483	$208,053,303	$493,952,265
2029	$34,070,470	$81,563,628	$99,399,983	$75,297,982	$212,214,369	$502,546,432

Project Use Power Revenues – Annually, WAPA-SN and Reclamation estimate the power O&M costs associated with project-use to develop water rates. The charges for project use power are collected by Reclamation through the CVP project use customers' water rates, and Reclamation transfers those revenues to WAPA-SN. The estimate is developed using the current cost sub-allocation methodology.

CVP Power Revenues – The power repayment study refers to these revenues as Firm Commercial Revenues. Estimated CVP power revenues are derived by determining the gross revenue requirement first, then subtracting the expected revenues from project-use power, CVP transmission, COTP transmission, PACI transmission, and other sources of revenues which results in the "net", or power revenue requirement. Also included in the CVP Power Revenues is the custom product power purchased for WAPA-SN's customers. These costs are passed through to the customers using the CPP rate design.

Transmission Revenues – This category includes transmission revenues from the CVP point-to-point and NITS. WAPA-SN uses the transmission system to deliver CPP/SP for SMUD, Redding, NASA, and Full Load Service customers; therefore, corresponding transmission revenues are included in CVP power revenue category. All costs or credits associated with third party transmission are passed through to WAPA-SN's customers using this rate methodology.

Other Revenues - The revenue of sources in this category include non-firm energy sales, miscellaneous revenues, Scheduling Coordinator fees, Portfolio Management fees, administration fees, other pass-through revenues, and sales of Ancillary Services from customers in WAPA-SN's SBA.

Annual Operating Expense

Annual operating expense is repaid in the year it is incurred. Annual expenses are O&M, Purchased Power, Other, and Interest Expense. The PRR forecasts future expense based on WAPA and Reclamation operating budgets and planned repayment. Table 5 shows the projected annual expenses for October 1, 2025, through September 30, 2029.

Table 5 Projected Future Expense

Fiscal Year	Operation & Maintenance	Purchased Power	Other	Interest	Total
2025	$137,598,698	$199,409,866	$118,490,805	$8,471,222	$463,970,591
2026	$141,555,726	$203,393,096	$118,955,412	$9,133,348	$473,037,582
2027	$144,825,643	$207,455,990	$119,397,213	$9,630,913	$481,309,759
2028	$148,326,316	$211,600,141	$119,854,777	$9,805,363	$489,586,597
2029	$151,740,564	$215,827,176	$120,314,939	$10,306,407	$498,189,086

O&M Expense – As published in the August 2022, PRR forecast, WAPA-SN's and Reclamation's O&M expense is based on budget projections for the period FY 2025 through FY 2029, and then held constant through the end of the PRS repayment period. FY 2025 through FY 2029 projections are listed in the table below.

Table 6 Agency Projected Future Operation & Maintenance Expenses

Agency	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Reclamation	$58,204,706	$60,258,673	$62,066,433	$63,928,426	$65,846,279
WAPA-SN	$79,393,992	$81,297,053	$82,759,210	$84,397,890	$85,894,285
Total O&M	$137,598,698	$141,555,726	$144,825,643	$148,326,316	$151,740,564

Purchase Power Expenses – Purchase power expense includes WAPA-SN's purchase power costs for PU and FP customers, purchases for reserves, and purchase power for the Washoe Project. The purchase power expenses are directly related to the forecast of replacement energy prices and volume of purchased energy. The purchase price of energy is set by supply and demand in the energy markets. Project-Use and First Preference Power are based on customer requests and operational changes for the max-peaking program, forward purchases for project-use and first preference power could occur, but none are projected for this rate period.

Estimates for FY 2025 through FY 2029 purchase power expenses include the following:

Table 7 Projected Purchase Power Expense

Category	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Custom Product & Supplemental Power	$196,053,275	$199,974,340	$203,973,827	$208,053,303	$212,214,369
HBA Costs	$3,108,192	$3,170,356	$3,233,763	$3,298,438	$3,364,407
Washoe Purchase Power for BR	$248,400	$248,400	$248,400	$248,400	$248,400
Total	**$199,409,866**	**$203,393,096**	**$207,455,990**	**$211,600,141**	**$215,827,176**

1. **Custom Product & Supplemental Power**: This is generally covered via corresponding revenues.

2. **HBA Costs:** Host Balancing Authority (HBA) costs for FY 2025 are estimated at $3.0 million.

3. **Washoe Purchase Power:** Washoe's output is included as part of the Base Resource as defined under the Marketing Plan. Energy available after meeting Washoe project use requirements is sold to the CVP at full cost recovery rate.

Project Use and First Preference Power: Based on customer requests and operational changes for the max-peaking program, forward purchases for project-use and first preference power could occur, but none are projected for this rate period.

Other Expenses – There are following six main sources of expenses included in this category. Note, most are pass-through and offset by revenue collection.

1. **CAISO Expenses** – Expenses billed to WAPA-SN from CAISO operations are recovered from customers. The CAISO Expense is offset through revenue collection. WAPA-SN's FY 2025 estimate is $44.2 million.

2. **Third Party Transmission and Wholesale Distribution Charges** – All expenses or credits associated with third party transmission and Wholesale Distribution Charges are passed through to WAPA-SN's customers using this service. The Third-Party Transmission Expense and Wholesale Distribution Charges are offset through revenue collection.

3. **Miscellaneous Expense** is estimated at $3.2 million for FY 2025. This category includes estimates for the COTP leased capacity, Trinity Assessment, WECC dues, COI, and Path Operator costs.

4. **Purchases for the SBA**: This generally is offset through sales, and any surplus or shortage is recovered in the PRR.

5. **Resource Adequacy/Flexible Resource Adequacy**: This is generally covered via corresponding revenues.

Interest Expense

Annual interest expense is determined by multiplying the various unpaid investments by the appropriate interest rate. Forecast growth in interest expense is attributed to budgeted capital work plans submitted by WAPA and Reclamation as discussed in the Capital Investment Section.

Aid to irrigation is non-interesting bearing. The remaining investment interest rates are set by the Department of Treasury. Interest rates on FY22 unpaid investments range between 3.0% - 4.625%.

Net Revenues for Project Repayment

The revenues remaining after repayment of annual expenses will first repay the remaining balance of the capitalized deficits, if any, and the remaining balance of other power investment including Irrigation Aid will be paid. Deferring payment of annual expenses is allowed under RA6120.2 for short periods of time. When repayment of annual expense or interest is deferred, causing a deficit, a loan is taken out for the deficit amount, at the current year's interest rate. The loan, plus interest, must be repaid from future years' revenues. RA6120.2 generally determines repayment hierarchy where highest interest-bearing investments are paid first, within allowable repayment periods. For the effective rate period, net revenue averages approximately $4.6 million per year. Table 8 provides the projected net revenues for the rate adjustment period.

Table 8 Projected Net Revenues

Time Period	Total Revenues	Total Expenses	Net Revenues
FY 2025	470,085,718	463,970,591	6,115,127
FY 2026	477,165,548	473,037,582	4,127,966
FY 2027	485,215,523	481,309,759	3,905,764
FY 2028	493,952,265	489,586,597	4,365,668
FY 2029	502,546,432	498,189,086	4,357,346
Average	**$485,793,097**	**$481,218,723**	**$4,574,374**

Federal Investment

Capitalized Power Investments - Cumulative Federal Investment through FY 2022 totals $959.9 million and includes all CVP, COTP, and PACI project original investments, additions to investments and replacements of investments. Forecast Commercial Power Investments is related to normal inflation and relatively small increases in capitalized improvements and replacements projected in agency work plans.

Irrigation Aid - As of FY 2022, $66 million of Irrigation Aid has been assessed and a modest $1 million increase per year is forecasted for future years.

Table 9 5-Year Projected Capital Investment

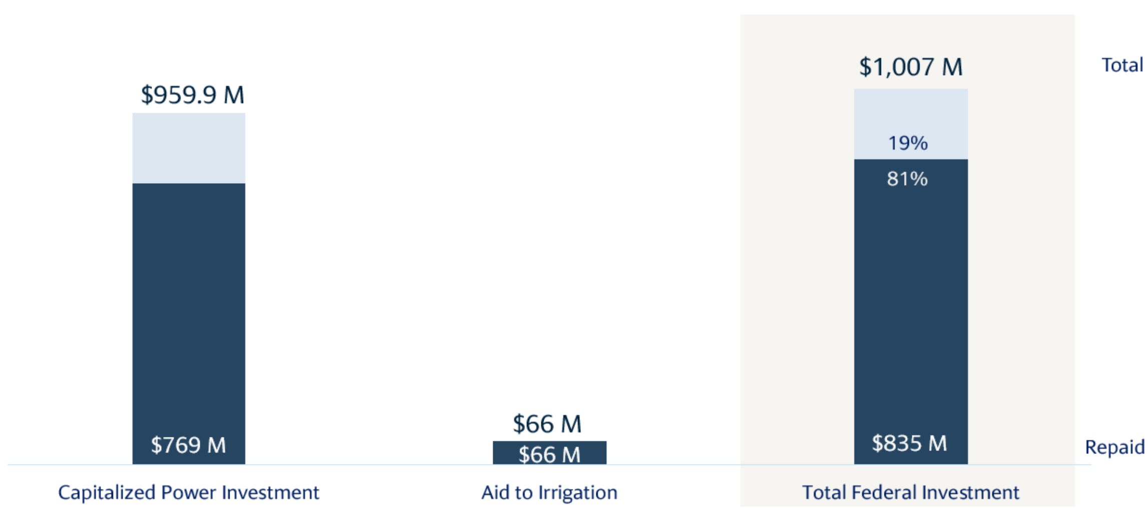
CVP Capital Investments	Capitalized Power Investments	Aid to Irrigation	Total Federal Investment
Investments as of FY22	**959,901,856**	**66,346,321**	**1,026,248,177**
Forecasted FY 2023	18,528,293	1,000,000	19,528,293
Forecasted FY 2024	16,708,071	1,000,000	17,708,071
Forecasted FY 2025	29,029,516	1,000,000	30,029,516
Forecasted FY 2026	31,249,646	1,000,000	32,249,646
Forecasted FY 2027	20,620,272	1,000,000	21,620,272
Forecasted FY 2028	10,307,388	1,000,000	11,307,388
Forecasted FY 2029	22,082,340	1,000,000	23,082,340
Forecast through FY 2029	**1,108,427,383**	**73,346,321**	**1,181,773,704**

Status of Repayment

The Status of Repayment is published annually in WAPA's The Source, https://www.wapa.gov/about-wapa/the-source/

Table 10 charts the Status of Repayment for FY22 Capitalized Power Investments and Aid to Irrigation. The dark blue is what has been repaid and the light blue is the unpaid amount. The paid and unpaid amounts are stacked to total the Cumulative Federal Investment.

Table 10 FY22 CVP Status of Repayment



Capitalized Power Investments - Original CVP plant investment and additions allocated to preference power must be repaid with interest within fifty years after the facility is placed in service. Replacements must be repaid within the established service life of each piece of equipment, or fifty years, whichever is shorter. Cumulative Federal Investment through FY 2022 totals $959.9 million with $769 million repaid.

Irrigation Aid - As of FY 2022, $66 million of Irrigation Aid has been assessed and repaid. Irrigation Aid is non-interest bearing and repayment is due by FY 2030.

Total Federal Investment - Combining the Capitalized Power Investment and the Irrigation Aid, the Total Federal Investment through FY22 is $1,007 million. Approximately 81% is repaid. Original investment and Aid to Irrigation must be repaid by 2030.

RATE SCHEDULE CHARGE COMPONENTS

The rate structure consists of three charge components in the schedules:

1) **Component 1** is a formula rate or penalty. Details for component 1 are found within each individual Rate Schedule.

2) **Component 2** is Standard for all Rate Schedules.
   Any charges or credits associated with the creation, termination, or modification to any tariff, contract, or rate schedule accepted or approved by FERC or other regulatory bodies will be passed on to each relevant customer. The charges or credits apply to the service to which this rate methodology applies. When possible, WAPA-SN will pass through charges or credits directly to the customer in the same manner WAPA-SN is charged or credited. When not possible, the charges or credits will be passed through using Component 1 of the formula rate.

3) **Component 3** is Standard for all Rate Schedules.
   Any charges or credits from the HBA for providing this service will be passed on to each relevant customer. When possible, WAPA-SN will pass through charges and credits directly to the customer in the same manner WAPA-SN is charged or credited. When not possible, the charges or credits will be passed through using Component 1 of the formula rate.

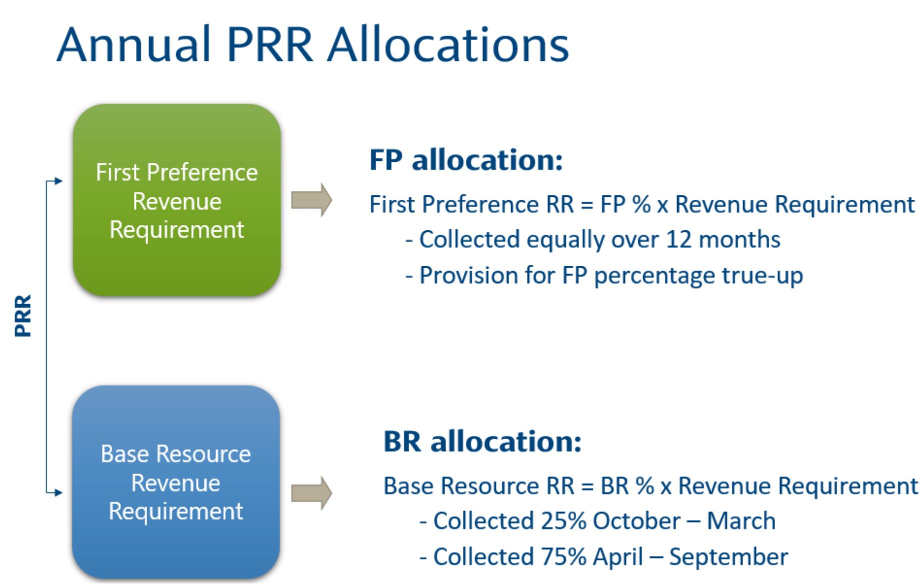
PROPOSED POWER RATE FORMULAS

CVP Proposed Rate Formula for CV-F14 Base Resource and First Preference Power

Power Revenue Requirement (PRR)

The PRR for BR and FP power deliveries includes the following expenses: CVP network transmission, annual investment repayment, power purchases for Day-Ahead firming the BR and FP power, power purchase for project-use and FP Customers (FPC), interest expense, operation, and maintenance (O&M) expense allocated to power, and the Washoe project annual PRR that remains after project use loads are met. Revenues from project use, transmission, ancillary services, and other services are applied to the power revenue requirement, and the remainder is collected from BR and FP customers.

Any charges or credits associated with the creation, termination, or modification to any tariff, contract, or rate schedule accepted or approved by FERC or other regulatory body will be passed on to each relevant customer. The FERC's or other regulatory bodies accepted, or approved charges or credits apply to the service to which this rate methodology applies. When possible, WAPA-SN will pass through directly to the relevant customer FERC's or other regulatory bodies accepted or approved charges or credits in the same manner WAPA-SN is charged or credited. If FERC's or other regulatory bodies accepted or approved charges or credits cannot be passed through directly to the relevant customer in the same manner WAPA-SN is charged or credited, the charges or credits will be passed through using Component 1 of the formula rate.



Component 1

Power Revenue Requirement (PRR) - WAPA-SN will develop the PRR before the start of each FY. The PRR will be divided into two 6-month periods, October through March, and April through September, based on FP and BR percentages. The PRR will be reviewed in March of each year. If there is a change of $5 million or more, the PRR will be recalculated for the entire FY. The PRR is allocated to FP Customers and BR Customers based on formula rates, as adjusted for Hourly Exchange (HE), FP true-up calculation and midyear adjustments.

FP Power Formula Rate:

The annual FP customer allocation is equal to the annual PRR multiplied by the relevant FP percentage.

$$\text{FP Revenue Requirement} = \text{PRR x FP \%}$$

$$\text{FP Customer Percentage} = \frac{\text{FP Customer Load}}{\text{Gen + Power Purchases - Project Use}}$$

Where:

FP Customer Load =	FP Customer's forecasted annual load (MWh)
Gen =	Forecasted annual CVP, Lewiston and Washoe generation (MWh)
Power Purchases =	Power purchases for Project Use and FP loads (MWh)
Project Use =	Forecasted annual Project Use loads (MWh)

WAPA-SN will develop each FP customers' percentage before the start of each FY, and review in March every year. If there is a change of more than one-half of 1 percent, the percentage will be revised for the full FY and billing will be adjusted over the remaining 6 months.

In addition, WAPA-SN will perform a true-up each year to ensure FP Customers pay their proportionate share of the PRR. The FP customers' percentage is limited to a percentage of the PRR.

Table 11 First Preference Percentage Calculation Estimated FY 2023

FY 2023 FP Customer Percentages	Sierra Conservation Corps (SCC)	Calaveras Public Power Agency (CPPA)	Trinity Public Utilities District (TPUD)	Tuolumne Public Power Agency (TPPA)	Chicken Ranch Rancheria (CRR)
Washoe Generation - MW	1,853	1,853	1,853	1,853	1,853
Lewiston Generation - MW	3,060	3,060	3,060	3,060	3,060
Load forecast - MW	9,385	34,281	142,452	45,618	4,196
CVP Generation - MW	3,012,000	3,012,000	3,012,000	3,012,000	3,012,000
Project Use load forecast - MW	647,000	647,000	647,000	647,000	647,000
Project Use purchase	0	0	0	0	0
FPC percentages	0.40%	1.45%	6.01%	1.92%	0.18%

The FPCs' share of the annual PRR is determined by summing all the FPCs' percentages and multiplying that sum by the annual PRR as shown in the table below. See Table 12 below that shows the FPCs' estimated revenue requirement.

Table 12 First Preference Revenue Requirement Estimated FY 2025

FPC	FPC Estimated Percentage of PRR	FY 2025 PRR	FY 2025 FPC Estimated Rev Req
SCC	0.40%	$73,822,854	$292,351
CPPA	1.45%	$73,822,854	$1,067,868
TPUD	6.01%	$73,822,854	$4,437,388
TPPA	1.92%	$73,822,854	$1,421,013
CRR	0.18%	$73,822,854	$130,719
Total	**9.96%**		**$7,349,339**

The FP customers' obligation may be adjusted at mid-year. As part of WAPA-SN's review of the PRR during March of each year, the FP customers' share of the PRR may change. If WAPA-SN changes the PRR and/or the FP customers' load percentage changes, then the percentage will be revised for the full FY and billing will be adjusted over the remaining 6 months.

The table below shows the maximum percentages for each FP customer that will be applied to the PRR. FP percentages cannot exceed the maximum except in instances where a FP customers' percentage increases due to load growth. If maximum percentages are exceeded for more than one year, WAPA-SN will reevaluate and update customer maximum percentages.

Table 13 First Preference Maximum Percentages

FP Maximum Percentages	
FP Customer	**Maximum FP Customer Percentage Applied to the PRR**
Sierra Conservation Center	1.58%
Calaveras Public Power Agency	3.81%
Trinity Public Utilities District	12.01%
Tuolumne Public Power Agency	3.16%
Chicken Ranch Rancheria	0.96%
Total	**21.52%**

Base Resource Revenue Requirement/Formula Rate

After the FP customers' share of the annual power revenue requirement has been determined, the remainder of the annual power revenue requirement is recovered from the BR customers (BR revenue requirement). The BR revenue requirement will be collected in two 6-month periods. For October through March, 25 percent of the BR revenue requirement will be collected. For April through September, 75 percent of the BR revenue requirement will be collected. Allocating the BR revenue requirement in this manner more closely aligns the BR revenue requirement with the BR available during the two six-month periods. CVP generation is greater in the April through September period than the October through March period. The shifting of the BR revenue requirement will help minimize monthly per unit cost variations for the customers.

A BR monthly revenue requirement is calculated by dividing the BR estimated 6-month revenue requirement by 6 months. A customer's BR costs are independent of the BR received. BR energy not used by any preference customer will be sold, if possible, and the revenues will be utilized to off-set the costs in the BR revenue requirement.

BR Formula Rate:

The annual BR customer allocation is equal to the annual PRR multiplied by the relevant BR percentage. To Variable Resources (VR) Customers requesting scheduling for this service. A scheduling charge is applicable to VR customers requesting WAPA-SN to schedule CPP purchases.
RR less the annual FP customer allocation.

BR Revenue Requirement = (PRR x BR%)

BR% = BR percentage for each customer as indicated in the BR contract after adjustments for programs, such as HE, if applicable.

After the FP Customers' share of the annual PRR has been determined, including a prior period true-up from the FP formula rate, the remainder of the annual PRR is recovered from the BR Customers. The BR Revenue Requirement will be collected in two 6-month periods; 25% for October through March, and 75% for April through September.

Note: (PRR - FPC RR) = BR RR Each customer's BR percentage is applied to the CVP monthly BR revenue requirement to determine that customer's cost for BR power for that month. There may be adjustments to the customer's BR percentage as provided for in the BR contract.

Hourly Exchange Program - As provided in Exhibit B of the BR Contract, the BR customers' power bills will be adjusted to reflect transactions into and out of the hourly exchange program. If unused BR is not utilized through the Exchange Program, it will be sold, and the revenues will be used to reduce the BR revenue requirement. The customer whose BR was not utilized in the exchange program will not have their percentage adjusted. A comprehensive example of these transactions is shown in the table below. As provided in Exhibit B of the BR Contract, the BR customers' percentage can also be adjusted for the seasonal exchange program.

Table 14 Hourly Exchange Sample Calculation

Hourly Exchange Program								
Customer	Assumed Contract BR %	BR RR ($75)	BR (MWh) (30)	Excess BR Load (EE)	Customer wanting EE (MWh)	BR delivered (adj. to HE)	Revised BR %	Revised BR RR
A	20	$15.00	6	3	0	3	10.00	$7.50
B	10	$7.50	3	0	1	4	13.33	$10.00
C	70	$52.50	21	0	2	23	76.67	$57.50
Total	100	$75.00	30	3	3	30	100	$75.00
Assumptions: Base Resource RR is $75 Customers A, B, and C are Full Load Service Customers Numbers may not calculate exactly due to rounding								

CVP Proposed Rate Formula for CPP-3 Custom Product Power

Rate Comparison - The CPP-3 CPP cost recovery is not changing from the existing methodology and remains 100 percent pass through under this rate schedule.

Under the proposed formula rate, Component 1, all costs incurred in providing CPP will be passed through to the customer. The CPP includes, but is not limited to, supplemental power and Base Resource (BR) firming power. If in the event customer advance funding is used to purchase CPP, then allocation of surplus CPP sales will be determined based on customer's account status. Proceeds from the sale of surplus CPP will be applied to reduce the Power Revenue Requirement.

Variable Resources (VR) customers requesting scheduling for this service will pay a scheduling charge to recover WAPA-SN's cost for scheduling VR CPP service. The VR scheduling charge will apply per schedule per day to cover the administrative costs for procuring and scheduling CPP. If the actual number of schedules for the month is not available, WAPA-SN will estimate the number of schedules for the month and apply the VR scheduling charge to the estimated number of schedules.

Rate Recovery and Application - The CPP cost recovery methodology is not changing and remains 100 percent pass through under this rate schedule. The formula rate for CPP applies to power supplied by WAPA-SN to meet a customer's load. The VR customer charge is to recover WAPA-SN's cost for scheduling VR customer's CPP service.

PROPOSED TRANSMISSION RATE FORMULAS

Cost-of-Service Study and Facility Assignment

WAPA-SN uses a detailed cost-of-service (COS) study to determine the revenue requirement that will be recovered through the transmission service proposed formula rate for firm and non-firm, point-to-point transmission service. Each facility is reviewed to determine its functional use allocation. The costs for facilities that support the transfer capability of the transmission system (excluding generation ties and radial lines) are included in the transmission revenue requirement. WAPA-SN uses FERC guidelines and orders to determine if a facility is a direct assigned facility (non-transmission) or a network facility, supporting the transmission function.

CVP TRR Calculation (Numerator)

Based on actual and projected data, WAPA-SN calculates the annual revenue requirement for providing transmission service. The cost categories are operation O&M, depreciation, and interest expense and any transmission-related costs or credits. WAPA-SN's cost for scheduling, system control and dispatch service associated with the transmission service is included in these cost categories. The cost components are allocated to the transmission function based on a ratio of transmission plant to total plant resulting from functional-use assignment. The sum of, O&M, depreciation, interest, and other costs, multiplied by the ratio of assets assigned to transmission is the annual transmission revenue requirement (TRR). The TRR is credited or reduced by (1) payments under existing contracts for use of the CVP transmission facilities that are not charged the CVP transmission rate, (2) short-term, point-to-point CVP transmission service revenues, and (3) Unreserved Use Penalty revenue in excess of CVP transmission costs.

The COS study for the proposed FY 2025 formula rate is based on the estimated FY 2024 costs for O&M, depreciation, interest expense, other adjustments, and anticipated changes in plant for FY 2023. See summary in Table 15.

Table 15 CVP Cost of Service Study

Central Valley Project Cost of Service Study (2025 Estimate)			
Ratio and Costs	**Total Costs**	**Transmission**	**Non-transmission**
Ratio (Transmission/Non-transmission)	100.00%	65.14%	34.86%
O&M	$132,729,247	$49,676,303	$83,052,944
Depreciation	$18,029,103	$7,201,883	$10,827,220
Interest	$8,688,080	$3,067,540	$5,620,540
CVP Transmission Reservation Fee and other fixed charge transmission miscellaneous revenue		($390,724)	
Short term Point-to-Point CVP Transmission Sales		($5,320,318)	
Total CVP Transmission Revenue Requirement		**$54,625,409**	

CVP TTc and NITSc Calculation (Denominator)

After identifying the annual revenue requirement related to the transmission system facilities, WAPA-SN calculates the denominator. The COS study for the CVP point-to-point transmission service proposed formula rate uses the rolling 12 - month average coincident peaks of NITS customers at the time of the monthly CVP system peak, and the total transmission capacity under long-term contract, for the rate adjustment period. For rate design purposes, WAPA-SN's use of the transmission system to meet its statutory obligations is treated as NITS. For this COS study, the city of Roseville's usage is net of WAPA-SN's power deliveries, adjusted for displacement. Table 16 below summarizes capacity used in the denominator.

Table 16 Transmission System Usage

Central Valley Project Capacity (TTc and NITSc)	Estimated 2025 Monthly Quantity (MW)
Long-term firm contracts (CVP TTc)	973
Forecasted average of network loads at the time of the monthly system peaks (NITSc)	1,371
Total	**2,344**

CVP Firm Point-to-Point Rate and NITS Calculation

The next step in the rate design is to allocate total transmission costs to the CVP transmission services. First, WAPA-SN calculates the point-to-point transmission rate by dividing the annual transmission revenue requirement by the sum of the rolling 12-month average coincident peaks for all NITS Customers, and the total transmission capacity under long-term contracts between WAPA-SN and other parties. Second, the calculated point-to-point rate is multiplied by WAPA-SN's reserve capacity, under contract, to determine the amount of revenue from point-to-point transmission service. Third, the difference between WAPA-SN's CVP TRR and point-to-point transmission revenue is the NITS revenue requirement.

Table 17 below provides an example of the allocation of the TRR to point-to-point and NITS.

Table 17 TRR Allocation (April 2025 Estimates)

Steps in Allocation	Transmission Service	Amount
Step 1: Determine TRR	CVP Transmission Revenue Requirement	$5,4625,409
Step 2: Determine Capacity	Transmission System Usage (Table 16) (Converted to kW-Month)	2,344,084
Step 3: Determine point –to-point Transmission Rate: TRR /Capacity	Point-to-point transmission per unit charge ($/kW-Month) = (TRR/12)/(MW X 1000)	$1.94
Step 4: Determine annual revenue from P-t-P (Rate x Capacity)	Revenues from the sale of long-term firm P-t-P transmission	($22,651,440)
Step 5: Determine NITS annual revenue requirement (TRR less revenue from point-to-point)	Total CVP transmission revenue requirement for NITS	$31,973,969
Step 6: Determine NITS Monthly (NITS annual/12)	Monthly NITS Revenue Requirement	$2,664,497

To ensure full cost recovery and maintain rate stability, WAPA-SN may revise the rate resulting from Component 1 of the proposed formula rate based on either: (a) updated financial data available in March of each year; or (b) a change in the numerator or denominator that results in a rate change of at least $0.05 per kW month. As previously noted, the proposed rates resulting from Component 1 may be discounted for short term sales, payments under existing contracts for use of the CVP transmission facilities that are not charged the CVP transmission rate, and Unreserved Use Penalty revenue in excess of cost.

Based on Table 17 the proposed CVP point-to-point transmission formula rate effective April 1, 2025, is $1.94 per kW-month, a 4.9 percent increase from the rate effective April 1, 2023, $1.85 per kW-month. The revenue requirement increased slightly (Table 18), and the usage projection (Table 19) had an increase in assets supporting the transmission function, not a rate methodology change. A comparison of the CVP revenue requirement components for the current CVP rate and the proposed is summarized in Table 18.

Table 18 Comparison of Transmission Revenue Requirement

CVP Transmission Revenue Requirement	Current FY 2023 Transmission Revenue Requirement	Estimated FY 2025 Transmission Revenue Requirement
O&M	$44,035,477	$49,676,303
Depreciation	$6,556,849	$7,201,883
Interest	$5,147,588	$3,067,540
Credit/Expenses	($390,724)	($390,724)
Short term Pt-to-Pt CVP Transmission sales	(5,952,808	(5,320,318
Total Transmission Revenue Requirement	**$49,396,383**	**$54,625,409**

Note: Numbers may not add due to rounding.

Table 19 compares current usage at 2230 MW-month increased by projected NITS to 2344 MW-month.

Table 19 Comparison of Transmission System Usage

Capacity	Current FY 2023 Average (MW month)	Estimated FY 2025 Average (MW month)
Long-term firm contracts	973	973
WAPA-SN's Use of Transmission System	1072	1223
Average 12-month network loads at the time of the CVP monthly system peaks	185	149
Total	**2230**	**2344**

The increase in current to estimated rate is due to NITS estimates and not a change in methodology.

CVP Proposed Rate Formula for CV-T4 Point-to-Point Transmission Service

Rate Comparison - Under the proposed formula rate, Component 1, the estimated firm, and non-firm point-to-point rate effective April 1, 2025, is $1.94 per kW-month. This is a 4.9-percent increase from the existing April 1, 2023, CVP firm and non-firm point-to-point rate of $1.85 per kW-month. The estimated rates resulting from the formula rate are subject to change prior to the rates taking effect.

Rate Recovery and Application - The formula rate for CVP transmission service is based on a RR that recovers: (1) the CVP transmission system costs for facilities associated with providing transmission service; (2) the non-facility costs allocated to transmission service; (3) costs include O&M costs, interest expense, depreciation expense, and other miscellaneous costs; (4) the cost for transmission scheduling, system control and dispatch service is included in O&M; (5) the pass through of FERC's or other regulatory body's accepted or approved charges or credits; (6) the pass through of the HBA's charges or credits; (7) any other statutorily-required costs or charges; and (8) any other costs associated with transmission service including uncollectible debt. Revenues from the sales of short-term, non-firm transmission will offset the TRR. Revenue from unreserved use of transmission penalties exceeding transmission service cost is applied as an offset to the TRR.

The formula rate applies to CVP firm point-to-point transmission service, existing CVP firm pre-Open Access Transmission Tariff (OATT) transmission service, and CVP non-firm transmission service.

CVP Proposed Rate Formula for CV-NWT6 NITS

The proposed rate formula for CVP NITS is based on the same transmission revenue requirement that is used for CVP point-to-point transmission rate. The NITS revenue requirement is the result of the CVP TRR less the CVP firm point-to-point transmission revenue requirement. Each NITS Customer's allocation is based on the following formula:

NITS Customer's monthly demand charge =
NITS Customer's load-ratio share times one-twelfth (1/12) of the Annual Network TRR

Where:

NITS Customer's load ratio share =	The NITS Customer's hourly usage (including behind the meter generation minus the NITS Customers' hourly adjusted Base Resource) coincident with the monthly CVP transmission system peak, averaged over a 12-month rolling period
Annual Network TRR =	The total CVP TRR, less revenues from long-term contracts for the CVP transmission between the WAPA-SN and other parties

The Annual Network TRR will be revised when the rate from Component 1 of the CVP transmission rate under proposed Rate Schedule CV-T4 is revised.

Below is a sample calculation for a NITS customer's monthly costs:

Table 20 Sample NITS Customer Monthly Calculation

	Steps in Monthly Billing Calculation	Units
A	NITS customer's usage at the time of the transmission system coincident peak (12-month average)	125 MW
B	Transmission System Coincident Peak (12-month average)	991 MW
C	NITS customer's resulting load ratio share (A/B)	12.6 %
D	Monthly Revenue Requirement	$1,824,170
E	**Customer's monthly costs for NITS (C x D)**	**$229,845**

COTP Proposed Rate Formula for COTP-T4 Point-to-Point Transmission Service

Rate Comparison - The existing rate schedule COTP-T3 calculates COTP Point-to-Point Transmission Service rates for three seasons, Spring, Summer, and Winter. The proposed COTP-4 rate schedule will have an annual rate and will no longer have separate seasonal rates. One rate is a simplified cost recovery and will reduce the demand on WAPA-SN's staff.

A comparison of the estimated rates resulting from Component 1 of the proposed formula rate for COTP firm point-to-point transmission service to the existing COTP firm point-to-point transmission service rates are shown in Table 21 below.

Table 21 Rate comparison COTP Firm & Non-Firm

Season	Existing Rates	Estimated Rates for Proposed Formula Rate	Percent Change
Spring	$3.61 $/MWh	$3.69 $/MWh	2%
Summer	$3.60 $/MWh		
Winter	$3.65 $/MWh		

The estimated firm point-to-point COTP transmission service rate increased due to an inflationary increase of 2% of the average of the seasonal rates costs, not a rate methodology change.

Rate Recovery and Application - The proposed formula rate for COTP firm and non-firm point-to-point transmission service is based on a RR that recovers: (1) the COTP transmission system costs for facilities associated with providing transmission service; (2) the non-facility costs allocated to transmission service; (3) the cost of scheduling system control and dispatch service associated with COTP transmission; (4) the pass through of FERC's or other regulatory body's accepted or approved charges or credits; (5) the pass through of the HBA's charges or credits; (6) any other statutorily-required costs or charges; and (7) any other costs associated with transmission service including uncollectible debt.

The proposed firm and non-firm formula rate include WAPA-SN's cost for transmission scheduling, and system control and dispatch service associated with COTP transmission. The proposed formula rate applies to COTP point-to-point transmission service. The rates resulting from Component 1 of the proposed formula rate may be discounted for short-term sales and revenue from COTP unreserved use penalties.

The annual revenue requirement used to develop the numerator in component 1 of the COTP firm and non-firm transmission service proposed formula rates are described below.

<u>Long-Term Capacity Rights</u> **-** WAPA-SN purchased rights to 50 MW of long-term capacity on the COTP transmission system. The total cost for the 50 MW is $22,135,045 which carries an annual interest payment of $198,717, plus average annual depreciation of $559,278.

<u>Leased Capacity</u> **-** WAPA-SN has 27 MW of COTP capacity, under Contract No. 93-SAO-00009, with the Transmission Agency of Northern California (TANC). The 2023 estimated lease costs associated with the 27 MW of COTP capacity from TANC is $578,034. These costs are derived from TANC's share of COTP costs associated with the 27 MW of COTP capacity.

COI Path Operator Costs - The California Independent System Operator (ISO) charges WAPA-SN monthly approximately $60,764 for the administration of the COI. WAPA-SN allocates the costs to both PACI and COTP based on capacity usage. COTP's annual share is estimated at approximately $223,678.

Facility Charges - WAPA-SN pays PG&E for their cost to install COTP facilities. This charge includes the ongoing costs of owning, operating, maintaining, and replacing such facilities, WAPA-SN allocates PGE's facility charge to DOE based on their participation share of COTP, $18,899 annually, is allocated to the COTP TRR.

DOE and US Fish and Wildlife Service and other federal uses Entitlement - As part of the COTP authorizing legislation, 100 MW is available for use by DOE, US Fish and Wildlife and other federal entities. The cost associated with the 100 MW entitlement is limited to O&M. COTP's credit is $12,599.

O&M Cost - WAPA's share of COTP annual O&M costs are projected at $921,181.

The estimated annual revenue requirement used to develop the numerator in component 1 of the COTP firm and non-firm transmission service proposed formula rates shown in Table 22 below allocates the COTP costs.

Table 22 COTP Estimated 2025 Annual Revenue Requirement

Leased Cap.	Facility Charges	DOE Credit Facility Use Charge	Path Opr. Costs	O&M	Depr.	Interest	Total
$578,034	$18,899	($12,599)	$223,678	$921,181	$559,278	$198,717	**$2,491,661**

Note: Numbers may not add due to rounding.

The denominator (Capacity) is the maximum capacity for firm transmission associated with WAPA-SN's rights under the current COI rating. Assuming a COI rating of 4,800 MW, WAPA-SN will have 77 MW of COTP transmission capacity: 50 MW long-term capacity rights, and 27 MW of leased capacity.

CVP Proposed Rate Formula for CV-UUP2 Unreserved Use

The UUP service is provided when a transmission customer uses transmission service that it has not reserved or uses transmission service in excess of its reserved capacity. This penalty is applicable to point-to-point (PTP) transmission customers using transmission not reserved or more than reserved, or network customers when they schedule delivery of off-system non-designated purchases using transmission capacity reserved for designated network resources. The formula rate for Unreserved Use Penalty (UUP) has three components.

Component 1 - A transmission customer that has not reserved capacity or exceeds its firm or non-firm reserved capacity at any point of receipt or any point of delivery will be assessed UUP.

The penalty charge for a transmission customer who engages in unreserved use is 200-percent of WAPA-SN's approved transmission service rate for PTP transmission service assessed as follows: (1) the UUP for a single hour of unreserved use will be based upon the rate for daily firm PTP service; (2) the UUP for more than one assessment for a given duration (e.g., daily) will increase to the next longest duration (e.g., weekly); and (3) the UUP for multiple instances of unreserved use (e.g., more than 1 hour) within a day will be based on the rate for daily firm PTP service. The penalty charge for multiple instances of unreserved use isolated to one-calendar week would result in a penalty based on the charge for weekly firm PTP service. The penalty charge for multiple instances of unreserved use during more than one week within a calendar month is based on the charge for monthly firm PTP service.

The UUP will not apply to transmission customers utilizing PTP transmission service under WAPA's Open Access Transmission Tariff (OATT) because of action taken to support reliability. Such actions include reserve activations or uncontrolled event response as directed by the responsible reliability authority such as SBA HBA, Reliability Coordinator, or Transmission Operator.

A transmission customer that exceeds its firm or non-firm reserved capacity is required to pay for all ancillary services identified in WAPA's OATT associated with the unreserved use of transmission service. The transmission customer or eligible customer will pay for ancillary services, in accordance with existing rate schedules, based on the amount of transmission service it used but did not reserve.

The UUP collected over and above the base PTP rate will be distributed to customers as a credit on future transmission revenue requirements.

Rate Comparison – The proposed CV-UUP2 continues a 200 percent penalty of the point-to-point transmission rate, for unreserved use of transmission except in emergencies or reserve sharing.

Rate Recovery and Applicability - The rate recovers the cost of transmission and applies a penalty for such unreserved use. The revenue resulting from the penalty portion will be distributed as a credit to the relevant TRRs. The penalty rate is applicable for all unreserved use of transmission and transmission in excess of reservation except, as may be determined by WAPA-SN, in emergencies or reserve sharing activations.

Power by Others

Rate Comparison - The cost of this service is not changing from the existing methodology and all costs are pass through under this rate schedule.

Rate Recovery and Application - These costs are fully recovered from the beneficiaries receiving this service, and this is not changing from the existing rate methodology.

PROPOSED ANCILLARY SERVICE RATE FORMULAS

CVP Proposed Rate Formula for CV-EID6 Energy Imbalance Service

Energy Imbalance Service is unchanged and continues to settle charges financially rather than with energy. EI Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load within the SBA over an hour or in accordance with approved policies and procedures. The deviation, in megawatts, is the net scheduled amount of energy minus the net metered (actual delivered) amount.

EI Service uses the deviation bandwidth that is established in the service agreement or Interconnected Operations Agreements.

Component 1 - EI Service is applied to deviations as follows unless otherwise dictated by contract or policy: (1) deviations within the bandwidth will be tracked and settled financially, at the greater of the California Independent System Operator (CAISO) market price, or WAPA-SN's actual cost; (2) negative deviations (under-delivery), outside the deviation bandwidth, will be charged the greater of 150-percent of the CAISO market price or 150-percent of WAPA-SN's actual cost; and (3) positive deviations (over-delivery), outside the deviation bandwidth, will be lost to the system, except for any hour when WAPA-SN incurs a cost to dispose of the energy, in which event the responsible party will bear that cost.

Deviations that occur due to actions taken to support reliability will be resolved in accordance with existing contractual requirements. Such actions include reserve activations or uncontrolled event responses as directed by the responsible reliability authority such as SBA, HBA, Reliability Coordinator, or Transmission Operator.

Components 2 & 3 - apply to this rate schedule. See Appendix A for a link to download the complete proposed rate schedule.

Rate Recovery and Application - WAPA-SN is proposing to maintain its existing tier methodology for EI. While FERC Order No. 890 defines a three-tier methodology, it allows alternatives to *pro forma* design if the rate schedule follows the intent of the three principles: (1) charges based on incremental cost or some multiple thereof; (2) charges must provide incentive for accurate scheduling; and (3) provisions address intermittent renewable resources (wind/solar) limited forecasting abilities by waiver of the most punitive penalties.

The EI service charge will be recovered from SBA customers that have contracted with WAPA-SN for this service. The revenues from EI service will be applied to the PRR.

Since the actual cost is calculated based on WAPA-SN's cost of generation, it is subject to change prior to the effective rate period.

Below is an example of how the EI charge is calculated using Component 1.

Table 23 Energy Imbalance Charge Calculation

Energy Imbalance Charge Example Calculation (Component 1)	
On October 1, Hour Ending 1, Customer A has:	
Scheduled Net Interchange	90 MW
Actual Net Interchange	102 MW
Actual Energy in excess of Scheduled	12 MW
Contractual Bandwidth	8 MW
Energy Imbalance for Hour Ending 1	**4 MW**

To derive the total monthly charge for Customer A, the EI is calculated for each 5-minute period that it occurs during the month.

The EI charge is based upon a comparison between the real-time energy pricing from the CAISO for each 5-minute period multiplied by 50 percent and WAPA-SN's actual cost for that same 5-minute period. The higher of the two is applied the OBD to derive the EI charge. EI charge for October 1, Hour Ending 1, is calculated as follows:

Table 24 Energy Imbalance Charge

October 1, Hour Ending 1	Price	Price Comparison	MW	Charge
WAPA-SN's Calculated Actual Cost	$18.27	Actual < 150% of Market	N/A	N/A
Real Time CAISO price ($21.84 * 150%) applied per rate schedule	$32.76	150% Market > Actual	4	$131.04
Note: EI charge for October 1, Hour Ending 1, is calculated as follows: 4 MW * $32.76 = $131.04				

Imbalances that occur because of action taken by the generator, at WAPA-SN's request, to support reliability will not be subject to penalties. Such actions include directives by SBA, HBA, Reliability Coordinators, or reserve activations and frequency correction initiatives.

To the extent that an entity incorporates variable resources, treatment of such will be determined in the associated contract.

CVP Proposed Rate Formula for CV-GID3 Generator Imbalance Service

GI Service is provided when a difference occurs between the scheduled and actual delivery of energy from an eligible generation resource within the SBA, over an hour, or in accordance with approved policies. The deviation in megawatts is the net scheduled amount of generation minus the net metered output from the generator's (actual generation) amount.

GI Service is subject to the deviation bandwidth established in the service agreement or Interconnected Operations Agreements.

Component 1 - WAPA CV-GID3 continues to settle charges financially rather than with energy. GI Service is applied to deviations as follows unless otherwise dictated by contract or policy: (1) deviations within the bandwidth will be tracked and settled financially at the greater of the California Independent System Operator (CAISO) market price or WAPA-SN's actual cost; (2) negative deviations (under-delivery), outside the deviation bandwidth, will be charged the greater of 150-percent of the CAISO market price or 150-percent of WAPA-SN's actual cost; and (3) positive deviations (over-delivery), outside the deviation bandwidth, will be lost to the system, except for any hour when WAPA-SN incurs a cost to dispose of the energy, in which event the responsible party will bear that cost.

Deviations that occur due to actions taken to support reliability will be resolved in accordance with existing contractual requirements. Such actions include reserve activations or uncontrolled event responses as directed by the responsible reliability authority such as SBA, HBA, Reliability Coordinator, or Transmission Operator.

To the extent that an entity incorporates intermittent resources, deviations will be charged as follows unless otherwise dictated by contract or policy: (1) deviations within the bandwidth will be tracked and settled financially at the greater of the CAISO market price or WAPA-SN's actual cost; (2) negative deviations (under-delivery), outside the deviation bandwidth, will be charged the greater of market price or actual cost (no penalty); and (3) positive deviations (over-delivery), outside the deviation bandwidth, will be lost to the system, except for any hour where WAPA-SN incurs a cost, then that cost will be borne by the responsible party.

Intermittent generators serving load outside of WAPA-SN's SBA will be required to dynamically schedule or dynamically meter their generation to another BA. An intermittent resource, for the limited purpose of these rate schedules, is an electric generator that is not dispatchable and cannot store its output, and therefore, cannot respond to changes in demand or respond to transmission security constraints.

Components 2 & 3 - apply to this rate schedule. See Appendix A for a link to download the complete proposed rate schedule.

Rate Recovery and Application - The GI charge will be recovered from SBA customers that have contracted with WAPA-SN for this service. The revenues from GI will be applied to the PRR. Since the actual cost is calculated based on WAPA-SN's cost of generation, it is subject to change prior to the effective rate period.

Below is an example of how the GI charge is calculated using Component 1.

Table 25 Generator Imbalance Charge Calculation

Generation Imbalance Service Charge Example Calculation (Component 1)	
If, on October 1, Hour Ending 1, Customer A has:	
Scheduled Net Interchange	102 MW
Actual Net Interchange	90 MW
Scheduled Generation in excess of Actual Generation (under delivery)	12 MW
Contractual Bandwidth	8 MW
Generator Imbalance for Hour Ending 1	**4 MW**

To derive the total monthly charge for Customer A, the GI is calculated for each 5-minute period that it occurs during the month.

The GI charge is based upon a comparison between the real-time energy pricing from the CAISO for each hour multiplied by 50 percent and WAPA-SN's actual cost for that same hour. The greater of the two is applied to OBD to derive the GI charge. Table 26 below is an example of how WAPA-SN determines the GI charge related to the GI in Table 25 above.

Table 26 Generator Imbalance Charge

October 1, Hour Ending 1	Price	Price Comparison	MW	Charge
WAPA-SN's Calculated Actual Cost	$18.27	Actual < 150% of Market	N/A	N/A
Real Time CAISO price ($21.84 * 150%) applied per rate schedule	$32.76	150% Market > Actual	4	$131.04
Note: GI charge for October 1, Hour Ending 1 is calculated as follows: 4 MW * $32.76 = $131.04				

GI charges will not apply because of action taken to support reliability. Such actions include reserve activations or uncontrolled event response as directed by the responsible reliability authority, such as, SBA, HBA, Reliability Coordinator, or Transmission Operator.

To the extent that an entity incorporates VRs, treatment of such will be determined in the associated contract.

GI and EI service charges/energy accounting will be netted within the hour or in accordance with approved policies and procedures, with charges for both services allowable only when the imbalances for both are deficit rather than offsetting (note that this only applies to netting within the bandwidth).

Table 27 Generator Imbalance Charge Example of an Addition

Example of an Addition Presented above:
Transmission Provider or SBA can charge customer for both GI and EI service in the same hour, but not if the imbalances offset each other. **Example of Offsetting:** • For example – Customer A » GI Service: -10MW deficit » EI Service: 5MW surplus » Customer A charged: 5MW (GI charge) **Example of Aggregating (increasing – absolute value)** • For example – Customer B » GI Service: -10MW deficit » EI Service: -10MW deficit » Customer A charged: -10MW for GI charge plus -10MW for EI charge

CVP Proposed Rate Formula for CV-RFS5 Regulation and Frequency Response Service

Regulation and Frequency Response Service (Regulation) is necessary to provide for the continuous balancing of resources and interchange, with load and for maintaining scheduled interconnection frequency at 60-cycles per second (60 Hz). Regulation is accomplished by committing on-line generation whose output is raised or lowered, predominantly using automatic generating control equipment, as necessary, to follow the moment-by-moment changes in load. The formula rate for regulation includes three components:

Component 1 - to the Regulation rate schedule states the formula rate is:

$$\text{Regulation Rate} = \frac{\text{Annual Regulation Revenue Requirement}}{\text{Annual Regulating Capacity (Kilowatt(kW))}}$$

Where:
The annual regulation revenue requirement includes: (1) the Central Valley Project generation costs associated with providing regulation, and (2) the non-facility costs allocated to regulation; and is calculated by dividing the Generation Revenue Requirement by the prior year plant capacity usage times the Regulation capacity.

The annual regulating capacity is one-half of the total regulating capacity bandwidths provided by WAPA-SN under the Interconnected Operations Agreements with SBA members.

The penalty for non-performance by an SBA customer who has committed to self-provision for their regulating capacity requirement will be the greater of 150 percent of WAPA-SN's actual costs or 150 percent of the market price.

WAPA-SN will revise the formula rate resulting from Component 1 based on either of the following two conditions: (1) updated financial data available in March of each year; or (2) a change in the numerator or denominator that results in a rate change of at least \$0.25 per kW month.

Components 2 & 3 - apply to this rate schedule. See Appendix A for a link to download the complete proposed rate schedule.

Rate Recovery and Application - The Regulation RR will be recovered from SBA customers that have contracted with WAPA for this service. The revenues from Regulation service will be applied to the PRR.

The following tables and discussion provide an example of how WAPA calculates the Regulation rate.

Table 28 Calculation of Regulation and Frequency Response Rate

Calculation of Regulation and Frequency Response Rate			
Step	**Line Description**	**Value**	**Reference or Calculation**
A.	Total Cost of Generation	$83,900,000	Table No. XV-2
B.	Plant Capacity (kW)	1,358,000	Table No. XV-3
C.	Cost/kW ($/kW) Year	$61.78	A/B
D.	Regulation Capacity (kW)	27,000	Table No. XV-4
E.	Regulation Revenue Requirement	$1,668,060	C * D
F.	Monthly Revenue Requirement	$139,005	E/12
G.	Rate $/kW-month	$5.15	F/D

Annual Revenue Requirement - The revenue requirement includes: (1) the CVP generation costs associated with providing regulation; (2) the non-facility costs allocated to regulation; (3) the cost of energy, capacity, or foregone generation that supports Regulation; (4) the pass through of HBA charges or credits; (5) the pass through of Commission or other regulatory body accepted or approved charges or credits; and (6) any other statutorily required costs or charges.

WAPA has calculated the annual revenue requirement for (1) and (2) above using a Commission recognized methodology for the various cost categories. The cost categories for facilities that support the generation capability of the CVP system include: (1) O&M, including unfunded benefits and BA costs, (2) interest expense and (3) depreciation expense. The CVP cost categories are allocated to the generation function based on a ratio of generation plant to total plant.

The following table provides an example of how the costs are assigned to generation.

Table 29 Allocation of Costs Assigned to Generation/Non-Transmission

Sample Allocation of Costs between Transmission and Non-Transmission/Generation			
Line Description	Total Cost (WAPA & Reclamation)	Transmission	Generation
A. CVP Plant Investment			
WAPA	$251,000,000	50%	50%
Reclamation	$496,000,000	0.00%	100%
B. O&M			
WAPA	$51,700,000	$25,850,000	$25,850,000
Reclamation	$34,500,000	$0	$34,500,000
C. Depreciation			
WAPA	$6,100,000	$3,050,000	$3,050,000
Reclamation	$5,300,000	$0	$5,300,000
D. Interest			
WAPA	$6,800,000	$3,400,000	$3,400,000
Reclamation	$11,800,000	$0	$11,800,000
F. Revenue Requirement	$116,200,000	$32,300,000	$83,900,000

After total cost of generation is determined, WAPA calculates the plant capacity, which includes the annual peak of the northern power plants generation at the time of the CVP system peak, plus the peak of San Luis and O'Neill power plants. Northern power plants include Trinity, Shasta, Keswick, Carr, Spring Creek, Folsom, Nimbus and New Melones power plants. Table 30 below provides an example of WAPA's plant capacity.

Table 30 Plant Capacity

Annual Coincident Peak for the CVP	
Annual Coincident Peak MW	**1,281**
Plus San Luis and O'Neill	**96**
Total Plant Capacity MW	**1,388**

Then, the total cost of generation ($86,515,382) is divided by the plant capacity (1,377,692 kW) to determine the cost per kW year ($62.80).

Customers who signed interconnected operations agreements will pay for Regulation based on one-half of the total regulating capacity bandwidths provided by WAPA under the interconnected operations agreements with SBA members. Table 31 provides an example of SBA customers' contractual regulating capacity bandwidths.

Table 31 Regulating Capacity Bandwidths under Contract

Regulating Capacity Bandwidths under IOAs	
SBA Customer	Regulating Capacity Bandwidth kW
Customer 1	6,000
Customer 2	10,000
Customer 3	2,000
Customer 4	9,000
Total Regulating Capacity	**27,000 kW**

Based on the regulating capacity in Table 31, WAPA's annual regulation revenue requirement is calculated as follows:

27,000 kW x $68.37 = $1,846,028

As previously stated, customers are billed monthly based on their contractual regulation capacity obligation.

When financial data is available in March 2024, the regulation rate will be updated. The rate will be reviewed again in September 2024 and if the $0.25 threshold is met, the rate will be changed beginning October 1, 2024.

PROPOSED SURPLUS PRODUCT RATE FORMULAS

CVP Proposed Rate Formula for CV-SSP3 Sale of Surplus Products

Sale of Surplus Products occurs when there is a sale of surplus energy and/or capacity products. This includes: (1) Energy, (2) Frequency Response Service, (3) Regulation, (4) Reserves, and (5) Resource Sufficiency. If any of the surplus products are available, WAPA-SN could make the product(s) available for sale, provided entities enter into separate agreement(s) which will specify the terms of sale(s). The formula rate for Sale of Surplus Products service includes three components:

Component 1 - WAPA-SN will determine the charge for each product at the time of sale to be the greater of WAPA-SN's cost or market rates, to include transmission charges. WAPA-SN will use a separate agreement(s) to specify the terms of sale(s). The customer may be responsible for acquiring additional transmission service necessary to deliver the product(s), for which a separate charge may be incurred from the transmission provider.

Components 2 & 3 - apply to this rate schedule. See Appendix A for a link to download the complete proposed rate schedule.

Rate Recovery and Application - SSP includes two products for sale: FRR and Resource Sufficiency. FRR is a product requirement based on Reliability Standard BAL-003-1.1, as approved by NERC. FRR is used to serve load immediately in the event of a system contingency. Generating units that are on-line and generating at less than maximum output provides these reserves. FRR supplies capacity that is available immediately to serve load and is synchronized with the power system. BANC implemented this requirement in January 2021, and WAPA therefore included this FRR service under the existing rate schedule CV-SSP2. The proposed Rate Schedule CV-SSP3 continues the same methodology.

Resource Sufficiency product supplies capacity to aid with EIM balancing resources to load forecast, and flexible ramping for aid with EIM 15-minute ramp up or down. WAPA bids energy into the EIM market for immediate dispatch. Resource Sufficiency is not a spin or regulation product. It is a product available to BANC EIM members as a balancing or flexible ramping product. WAPA's Merchant handles the sale and bidding of the products in EIM, which may result in adjustments to the EIM Transmission Customer Base Schedule market submission or bid ranges.

PROPOSED ENERGY IMBALANCE MARKET RATE FORMULAS

WAPA's formula rate schedules for: EIM Administrative Service (CV-EIM1S1), EIM EI Service (CV-EIM4S1), and EIM GI Service (CV-EIM9S1), accommodate WAPA's participation in EIM as a Transmission Provider within the BANC BAA. WAPA will participate in the EIM through BANC as the Balancing Authority and EIM Entity for the WAPA Sub-BAA. EIM settles EI and GI services differently than WAPA's existing rate schedules for similar services.

In EIM, CAISO economically dispatches energy under its EIM Tariff to meet the imbalances for loads and resources over multiple BAAs. CAISO provides a centralized, automated, and region-wide dispatch for imbalances. The new EIM Administrative Services formula rates will allow WAPA to pass through administrative costs incurred by WAPA resulting from its participation in EIM as a Transmission Provider. The Provisional Formula rates and cost allocation for Administrative, EI service and GI service will be in effect when WAPA is participating in the EIM and to the extent WAPA incurs associated settlements during market suspension or contingency.

EIM Market Cost Allocation Methodology

WAPA's EIM cost allocation methodology for EIM charges and/or benefits will be allocated to the CVP PRR, with an exception for Non-Conforming Loads which will be directly charged to the customer. BANC's, WAPA's, and Reclamation's EIM costs will be recovered over a period not to exceed three years. WAPA has identified four separate categories to allocate charges and/or benefits: (1) Conforming Loads; (2) Non-Conforming Loads; (3) small loads; and (4) statutory loads.

A Conforming Load is a type of load generally associated with a weather-based element, which is somewhat predictable based on given conditions. For Conforming Loads, WAPA will allocate the net EIM cost and/or net benefits to the CVP PRR.

A Non-Conforming Load changes abnormally – such as a factory that consumes high demand intermittently. For Non-Conforming Loads, WAPA will allocate the net EIM charges and/or benefits directly to the customer(s) with the Non-Conforming Load(s), in accordance with WAPA's applicable draft business practice, BP-44 "Energy Imbalance Market Settlements," posted on its OASIS.

EIM costs will be allocated to the CVP PRR for customers with small loads less than one MW. WAPA will assign load charges and benefits for those customers with statutory obligations, such as project use, to the CVP PRR. Customers with small loads or with statutory obligations will not directly pay nor benefit from EIM charges.

CVP Proposed Rate Formula for CV-EIM1S1 EIM Administrative Service Charges

This rate applies to WAPA-SN customers when WAPA-SN, as Transmission Provider, is participating in Energy Imbalance Market (EIM) and when EIM has not been suspended. To the extent WAPA-SN incurs EIM Administrative Service-related costs from the EIM Entity during periods of market suspension or contingency.

The EIM Administrative Service rate recovers the administrative costs for participating in the EIM by WAPA-SN as a Transmission Provider, including but not limited to such administrative charges as may be incurred by WAPA-SN from CAISO as the EIM Market Operator (MO) and/or BANC as the EIM Entity.

Unless such charges are allocated to the Transmission Customer directly by BANC, all Transmission Customers purchasing Long-Term Firm Point-to-Point Transmission Service, Short-Term Firm Point-to-Point Transmission Service, Non-Firm Point-to-Point Transmission Service, or Network Integration Transmission Service from WAPA-SN shall incur an EIM Administrative Service Charge from WAPA-SN.

CAISO's Administrative Service Charge, as defined in its Market Operator (MO) Tariff, is included in this rate. This rate also includes administrative charges assessed to WAPA-SN by BANC based on net energy load within the WAPA-SN Sub-BAA.

The formula rate for EIM Administrative Service includes three components:

Component 1 - EIM Administrative Service costs shall be sub-allocated to WAPA-SN's Transmission Customers based on load ratio share for the time in which WAPA-SN incurs EIM administrative costs.

Components 2 & 3 - apply to this rate schedule. See Appendix A for a link to download the complete proposed rate schedule.

Rate Recovery and Application - CV-EIM1S1, is unchanged and applicable under Attachment S, Addendum 1, of WAPA's Tariff. CV-EIM1S1 will apply when WAPA, as Transmission Provider, is participating in EIM and when EIM has not been suspended. EIM Administrative Service and the associated rate will apply in addition to the services provided under Schedule 1 of WAPA's Tariff, which are incorporated in existing WAPA transmission service rates. To the extent WAPA incurs EIM Administrative Service charges during periods of market suspension or contingency, as described in Attachment S, Section 11, of WAPA's Tariff, Schedule 1S and rate schedule CV-EIM1S1 will both apply to ensure that WAPA, as Transmission Provider, remains revenue-neutral for its participation in EIM.

EIM Administrative Service recovers the administrative costs for participating in EIM by WAPA as a Transmission Provider, including, but not limited to, such administrative charges as may be incurred by WAPA from the Market Operator (MO) and those MO charges passed through by the EIM Entity.

The MO's Administrative Service charge, as defined in the MO's Tariff, will be included in CV-EIM1S1. This rate also includes administrative charges assessed to WAPA by the EIM Entity based on net energy load within the WAPA Sub-BAA. The formula rate for EIM Administrative Service Charge will continue to be sub-allocated to WAPA's Transmission Customers based on load ratio share for the time-period in which WAPA incurs EIM administrative costs.

WAPA's costs for EIM start up, including software, hardware, and other features, to implement EIM, will not be included as administrative costs under this schedule. WAPA will allocate startup costs for EIM according to the cost allocation methodologies and procedures discussed under the Energy Imbalance Market Cost Allocation heading, below.

CVP Proposed Rate Formula for CV-EIM4S1 EIM Energy Imbalance Service

This rate applies to WAPA-SN customers receiving EI Service when WAPA-SN, as Transmission Provider, is participating in EIM and when EIM has not been suspended. To the extent WAPA-SN incurs EIM EI Service-related charges from the EIM Entity during periods of market suspension or contingency. The formula rate for EI Service includes three components:

Component 1 - EI Service is the deviation of the Transmission Customer's metered load compared to the load component of the Transmission Customer Base Schedule settled as Uninstructed Imbalance Energy (UIE) for the period of the deviation at the applicable Load Aggregation Point (LAP) price where the load is located.

EI Service penalties are applied to deviations as follows unless otherwise dictated by contract or policy: (1) negative deviations (under-delivery), outside the deviation bandwidth, will be charged the greater of 50-percent of the CAISO market price or 50-percent of WAPA-SN's actual cost; and (2) positive deviations (over-delivery), outside the deviation bandwidth, will be lost to the system, except for any hour when WAPA-SN incurs a cost to dispose of the energy, in which event the responsible party will bear that cost.

Deviations that occur due to actions taken to support reliability will be resolved in accordance with existing contractual requirements. Such actions include reserve activations or uncontrolled event responses as directed by the responsible reliability authority such as SBA, Host Balancing Authority (HBA), Reliability Coordinator, or Transmission Operator.

Components 2 & 3 - apply to this rate schedule. See Appendix A for a link to download the complete proposed rate schedule.

Rate Recovery and Application -CV-EIM4S1 for Energy Imbalance Service, is unchanged and applicable under Schedule 4S of the Tariff. In accordance with Attachment S, Section 11, of WAPA's Tariff, Schedule 4 of the Tariff will apply when WAPA is not participating in EIM or when EIM has been suspended. To the extent WAPA incurs EIM EI Service-related charges from the EIM Entity during periods of market suspension or contingency, as described in Attachment S, Section 11, of WAPA's Tariff, Schedule 4S and rate schedule CV-EIM4S will both apply to ensure that WAPA, as Transmission Provider, remains revenue-neutral for its participation in EIM.

EI Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within the WAPA-SN Sub-BAA. WAPA-SN offers this service when transmission service is used to serve load within the WAPA-SN Sub-BAA.

Unless subsequently imposed by California Independent System Operator (CAISO) as the Market Operator (MO) as part of the MO Tariff and promulgated by WAPA through rate proceedings, there shall be no incremental transmission charge assessed for transmission use related to the EIM. Transmission Customers must have transmission service rights, as set forth in Attachment S of WAPA's Tariff. The formula rate for EIM EI Service, CV-EIM4S1, is the deviation of the Transmission Customer's metered load compared to the load component of the Transmission Customer Base Schedule settled as UIE for the period of the deviation at the applicable LAP price where the load is located.

CVP Proposed Rate Formula for CV-EIM9S1 EIM Generator Imbalance

This rate applies to WAPA-SN customers receiving Generator Imbalance (GI) Service when WAPA-SN, as Transmission Provider, is participating in Energy Imbalance Market (EIM) and when EIM has not been suspended. To the extent WAPA-SN incurs EIM GI Service-related charges from the EIM Entity during periods of market suspension or contingency. The formula rate for GI Service includes three components:

Component 1 - GI Service penalties are applied to deviations as follows unless otherwise dictated by contract or policy: (1) negative deviations (under-delivery), outside the deviation bandwidth, will be charged the greater of 50-percent of the CAISO market price or 50-percent of WAPA-SN's actual cost; and (2) positive deviations (over-delivery), outside the deviation bandwidth, will be lost to the system, except for any hour when

WAPA-SN incurs a cost to dispose of the energy, in which event the responsible party will bear that cost.

Deviations that occur due to actions taken to support reliability will be resolved in accordance with existing contractual requirements. Such actions include reserve activations or uncontrolled event responses as directed by the responsible reliability authority such as SBA, Host Balancing Authority (HBA), Reliability Coordinator, or Transmission Operator.

To the extent that an entity incorporates intermittent resources, deviations will be charged as follows unless otherwise dictated by contract or policy: (1) negative deviations (under-delivery), outside the deviation bandwidth, will be charged the greater of market price or actual cost (no penalty); and (2) positive deviations (over-delivery), outside the deviation bandwidth, will be lost to the system, except for any hour where WAPA-SN incurs a cost, then that cost will be borne by the responsible party.

Intermittent generators serving load outside of WAPA-SN's SBA will be required to dynamically schedule or dynamically meter their generation to another Balancing Authority. An intermittent resource, for the limited purpose of these rate schedules, is an electric generator that is not dispatchable and cannot store its output, and therefore, cannot respond to changes in demand or respond to transmission security constraints.

Components 2 & 3 - apply to this rate schedule. See Appendix A for a link to download the complete proposed rate schedule.

Rate Recovery and Application - CV-EIM9S1 EIM GI Service is unchanged and continues to apply when a difference occurs between the output of a generator that is not an EIM Participating Resource located in the WAPA Sub-BAA, as reflected in the resource component of the Transmission Customer Base Schedule, and the delivery schedule from that generator to: (1) another BAA, (2) the BANC BAA, or (3) a load within the WAPA Sub-BAA. The EIM Entity does not allow EIM Non-Participating Resources.

Rate schedule CV-EIM9S1 is applicable under Schedule 9S of the Tariff. CV-EIM9S1 will apply when WAPA, as Transmission Provider, is participating in EIM and when EIM has not been suspended. In accordance with Attachment S, Section 11, of WAPA's Tariff, Schedule 9 and CV-EIM9S1 will both apply when WAPA is not participating in the EIM and when the EIM has been suspended. To the extent WAPA incurs EIM GI Service-related charges from the EIM Entity during periods of market suspension or contingency, as described in Attachment S, Section 11, of WAPA's Tariff, Schedule 9S and CV-EIM9S1 will both apply to ensure that WAPA, as Transmission Provider, remains revenue-neutral for its participation in EIM.

Unless subsequently imposed by the MO as part of the MO Tariff and promulgated by WAPA through rate proceedings, there will be no incremental transmission charge assessed for transmission use related to EIM GI Service. Transmission Customers must have transmission service rights, as set forth in Attachment S of the Tariff.

EIM GI Services does not have a direct rate component for EIM GI Services for EIM Non-Participating Resources. WAPA expects all EIM Participating Resources to directly settle with CAISO. However, if charges are allocated to the Transmission Provider by the EIM Entity, a Transmission Customer will be responsible for any pass-through charges/credits associated with applicable EIM GI Service charges allocated to WAPA, as Transmission Provider, for its participation in EIM, in accordance with CV-EIM9S1. Such charges will be included due to operational adjustments of any affected interchange. WAPA will directly assign charges and/or sub-allocate charges based on the Transmission Customer’s load ratio share. In the event the EIM Entity modifies its procedures to allow EIM Non-Participating Resources, WAPA will update CV-EIM9S1.

Appendix A – Proposed Rate Schedules

Clean and Redline versions also available for download, when posted, from the "Rate Order No. WAPA-207" page on the WAPA-SN at the following link:

Power

- **CV-F14 CVP Base Resource and First Preference Power** (PDF)
- **CPP-3 CVP-Custom Product Power** (PDF)

Transmission

- **CV-T4 CVP Point-to-Point Transmission Service** (PDF)
- **CV-NWT6 Network Integration Transmission Service** (PDF)
- **COTP-T4 COTP Point-to-Point Transmission Service** (PDF)
- **CV-TPT8 Transmission of Western Power by Others** (PDF)
- **CV-UUP2 Unreserved Use Penalties** (PDF)

Ancillary Services

- **CV-RFS5 Regulation and Frequency Response Service** (PDF)
- **CV-SPR5 Spinning Reserve Service** (PDF)
- **CV-SUR5 Supplemental Reserve Service** (PDF)
- **CV-EID6 Energy Imbalance Service** (PDF)
- **CV-GID3 Generator Imbalance Service** (PDF)

Surplus Products

- **CV-SSP3 Sale of Surplus Products** (PDF)

Energy Imbalance Market

- **CV-EIM1S1 Administrative Service** (PDF)
- **CV-EIM4S1 Energy Imbalance** (PDF)
- **CV-EIM9S1 Generator Imbalance** (PDF)

Appendix B – Rate Adjustment Procedures

WAPA's rate adjustment procedures are governed by the "Procedures for Public Participation in Power and Transmission Rate Adjustments and Extensions" published in the Federal Register at 10 CFR Part 903.2(e). These procedures give interested parties an opportunity to participate in the development of power rates.

I. Notice of Proposed Rate and Consultation and Comment Period: Initially, a notice of the Proposed Rate and official time for public participation must be published in the Federal Register. The notice of CVP's proposed non-firm power formula rate establishes a consultation and comment period. The period begins on the publication date of the Federal Register notice, which was August 30, 2023. During this period, interested parties may consult with and obtain information from WAPA's representatives. They may also examine data used in the power repayment studies and suggest changes. Specific details for providing comments are included in the Federal Register notice.

   A. Public Information Forum: WAPA's representatives present the Proposed Rate changes and answer questions. Those questions not answered at the public information forum receive written responses at least 15 days prior to the end of the consultation and comment period.
   B. Public Comment Forum: This forum provides a formal opportunity for interested parties to submit either written or oral comments to be shared with other attendees and WAPA representatives. Usually, WAPA does not respond to comments at this forum. However, comments are considered in developing the final rate adjustment, pursuant to 10 CFR 903.15 and 903.16.
   C. Written Comments: Interested parties may submit written comments and inquiries to WAPA during the consultation and comment period.
   D. Revision of Proposed Rate: After the close of the consultation and comment period, WAPA will review and consider comments. If appropriate, the Proposed Rate will be revised. If the Administrator determines that further public comment should be invited or is necessary, interested parties will be given a period of at least 30 days to submit additional comments concerning the Proposed Rate.
   E. Preliminary Decision on Interim Rate: Following the end of the consultation and comment period, the Administrator will develop provisional rates. The Deputy Secretary of Energy for the Department of Energy (DOE) has the authority to confirm, approve, and place this rate into effect on an interim basis. The decision, together with an explanation of the principal factors leading to the decision, will be published in the Federal Register.

F. <u>Final Approval of Interim Rate</u>: The Deputy Secretary will submit information concerning the interim rate to the Federal Energy Regulatory Commission (FERC) and request final approval. The response of FERC will be to:

1. give final confirmation and approval to the interim rate,
2. disapprove the interim rate, or
3. remand the matter to WAPA for further study.

The interim rate does not become final until it is approved by FERC.

Appendix C – Proposed Public Process Rate Adjustment Schedule

Public Process

Target Dates	Milestones
Sep 20, 2022	1st Informal Customer Meeting – CVP Rate Case WAPA-207 and Project Overview
Oct 31, 2022	2nd Informal Customer Meeting – Power Repayment Fundamentals
Nov 30, 2022	3rd Informal Customer Meeting – Transmission & Ancillary Services Repayment Fundamentals
May 2, 2023	4th Informal Customer Meeting – Process Update and Fundamentals Review
Aug 30, 2023	Federal Register Notice Published
	(Comment Period Begins)
Nov 15, 2023	Formal Customer Public Information & Comment Forum
Dec 29, 2023	Comment Period Ends
May 2024	Final Federal Register Notice Published
Oct 01, 2024	New Rate Schedules Effective

APPENDIX D – Proposed Federal Register Notice

Please access below link to access the Proposed Federal Register Notice:

https://www.federalregister.gov/documents/2023/08/30/2023-18748/formula-rates-for-central-valley-project-power-transmission-and-ancillary-services-and

Please access below link to access the Proposed Federal Register Notice Comment Period Extension:

https://www.federalregister.gov/documents/2023/11/17/2023-25432/extension-of-public-comment-period-for-central-valley-project-power-transmission-and-ancillary

APPENDIX E – Acronyms, Terms, and Definitions

As used in this Rate Order, the following acronyms, terms, and definitions apply.

BA:	As defined in WAPA's OATT, is Balancing Authority and is the responsible entity that integrates resource plans ahead of time, maintains load Interchange-generation balance within a Balancing Authority Area, and supports interconnection frequency in real time.
BAA:	As defined in WAPA's OATT, is Balancing Authority Area; the term Balancing Authority Area shall have the same meaning as "Control Area."
BANC:	As defined in WAPA's OATT, is Balancing Authority of Northern California (BANC). A joint powers authority that provides BA and other services to its members and other entities within the BAA. Members/entities of BANC may in turn provide transmission service to customers.
Base Resource:	As defined in Central Valley Project's 2025 Marketing Plan, Base Resource is the Central Valley and Washoe Project power (capacity and energy) output determined by WAPA to be available for marketing, including the environmental attributes, after meeting the requirements of project use and first preference customers, and any adjustments for maintenance, reserves, system losses, and certain ancillary services.
Transmission Customer Base Schedule:	As defined in WAPA's OATT, Attachment S, means Transmission Customers Base Schedule and is an energy schedule that provides Transmission Customer hourly-level forecast data and other information used as the baseline by which to measure Imbalance Energy for purposes of EIM settlement. The term "Transmission Customer Base Schedule" as used in this Tariff is synonymous with

the term “EIM Participant Base Schedule” used in the EIM Entity’s business practices and may refer collectively to the components of such schedule (resource, Interchange, Intrachange, and load determined pursuant to the EIM Entity’s business practices) or any individual components of such schedule. This term is synonymous to “Base Schedule.”

CAISO:	As defined in WAPA’s OATT, is the California Independent System Operator Corporation. A state-chartered, California, non-profit public benefit corporation that operates the transmission facilities of all CAISO participating transmission owners and dispatches certain generating units and loads. The CAISO is the MO for the EIM.
Capacity:	As defined in Central Valley Project’s 2025 Marketing Plan, is the electric capability of a generator, transformer, transmission circuit, or other equipment.
Conforming Load:	The term is not officially defined by CAISO at this time and will be addressed in the future. The following description reasonably aligns with the CAISO’s use of the term in defining load forecasting requirements under EIM: is the load that changes in a reasonably predictable, uniform manner that is environmentally driven. A conforming load has a load profile that is similar to the aggregated load profile. Due to conventional weather- and temperature-based patterns, conforming loads can be forecast with a high level of accuracy using historical and meteorological data.
CVP:	As defined in Central Valley Project’s 2025 Marketing Plan, is Central Valley Project. The multipurpose Federal water development project extending from the Cascade Range in northern California to the plains along the Kern River south of the city of Bakersfield, California.
DOE:	United States Department of Energy.

DOE Order RA 6120.2:	Department of Energy Order outlining power marketing administration financial reporting and rate-making procedures.
EI Service:	Energy Imbalance Service is an ancillary service that provides for the difference between the scheduled and the actual delivery of energy to a load within the Transmission Provider's Sub-BAA.
EIM:	As defined in CAISO's Business Practice Manual, means Energy Imbalance Market and is the rules and procedures in Section 29 of the CAISO Tariff governing the CAISO's operation of the Real-Time Market in BAAs outside of the CAISO BAA and the participation of EIM Market Participants in the Real-Time Market.
EIM Administrative Charge:	As defined in CAISO's Business Practice Manual, is the fee imposed on transaction in the energy imbalance market as described in section 29.11(i)(1) of the CASIO Tariff.
EIM Entity:	As defined in WAPA's OATT, Attachment S, is a BAA that enters into the MO's EIM Entity Agreement to enable the EIM to occur in its BAA. BANC is the EIM Entity for the BANC EIM Entity BAA. For the purposes of this Attachment S, the EIM Entity is the BANC EIM Entity or the entity selected by the BANC EIM Entity who is certified by the MO. WAPA-SN participates in the CAISO WAPA-SN EIM under the BANC EIM Entity.
EIM Participating Resource:	As defined in WAPA's OATT, Attachment S, is a resource or a portion of a resource: (1) that meets the Transmission Provider's eligibility requirements; (2) has been certified by the BANC EIM Entity for participation in the EIM; and (3) for which the generation owner and/or operator enters into the MO's EIM Participating Resource Agreement and any agreements as may be required by BANC and/or the BANC EIM Entity.
EIM Non-Participating Resource:	As defined on CAISO's website

	https://www.westerneim.com/Documents/EIMTrack5-MeteringFAQ.pdf, EIM Resource that does not participate in the Real-Time Market but is required to be identified in the EIM BAA for settling charges and payments related to nonparticipating load and nonparticipating resources.
Energy:	As defined in Central Valley Project's 2025 Marketing Plan, is measured in terms of the work it is capable of doing over a period of time; electric energy is usually measured in kilowatt-hours or megawatt-hours.
FERC:	Federal Energy Regulatory Commission.
Firm Point-To-Point Transmission Service:	As defined in WAPA's OATT, is transmission service reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to Part II of the Tariff.
First Preference Customers/Entity:	As defined in Central Valley Project's 2025 Marketing Plan, is a preference customer and/or a preference entity (an entity qualified to use, but not using, preference power) within a country or origin (Trinity, Calaveras, and Tuolumne) as specified under the Trinity River Division Act (69 Sta. 719) and the New Melones Project provisions of the Flood Control Act of 1962 (76 Stat. 1173, 1191-1192).
Frequency Response Reserve (FRR) or (FR):	As defined in SMUD's Operating Reserves OP-114, "NERC/WECC does not have an official definition for Frequency Response Reserve (FRR) yet. BANC is defining the FRR as an amount of reserve in MW that is synchronized to the system and can automatically respond to system frequency deviation. BANC in coordination with WAPA and SMUD procures and monitors sufficient FRR in both Day-Ahead scheduling process and Real-Time operations to ensure that BANC meet NERC Reliability Standard BAL-003-1.1 R1."
FY:	Fiscal year; October 1 to September 30.

Generating Unit: As defined in CAISO Tariff, is an individual electric generator and its associated plant and apparatus whose electrical output is capable of being separately identified and metered or a Physical Scheduling Plant that, in either case, is: located within the CAISO BAA (which includes a Pseudo-Tie of a generating unit to the CAISO BAA) or, for purposes of scheduling and operating the Real-Time Market only, an EIM Entity BAA; connected to the CAISO Controlled Grid, either directly or via interconnected transmission, or distribution facilities or via a Pseudo-Tie; and capable of producing and delivering net Energy (Energy in excess of a generating station's internal power requirements).

GI Service: Generator Imbalance Service is an ancillary service that provides for the difference between the output of a generator and the delivery schedule from that generator to: (1) another BAA, (2) the BANC BAA, or (3) a load within the Transmission Provider's Sub-BAA. GI Service during EIM participation is that associated with a generator that is not an EIM Participating Resource located in the Transmission Provider's Sub-BAA.

kW: As defined in WAPA's 2025 Marketing Plan, is kilowatt. A unit measuring the rate of production of electricity; one kilowatt equals one thousand watts.

LAP: Load Aggregation Point is a set of Pricing Nodes as specified in Section 27.2 of the CAISO Tariff that are used for the submission of Bids and Settlement of Demand.

Load Ratio Share: As defined in WAPA's OATT, is the ratio of a Transmission Customer's Network Load to the Transmission Provider's total load computed in accordance with Sections 34.2 and 34.3 of the Network Integration Transmission Service under Part III of the Tariff and calculated on a rolling twelve month basis.

Long-Term Firm Point-To-Point Transmission Service: As defined in WAPA's OATT, is Firm Point-To-Point Transmission Service under Part II of the Tariff with a term of one year or more.

MO: As defined in WAPA's OATT, Attachment S, is Market Operator. The entity responsible for operation, administration, settlement, and oversight of the EIM. The CAISO is the current MO of the EIM.

MO Tariff: As defined in WAPA's OATT, Attachment S, is those portions of the MO's approved tariff, as such tariff may be modified from time to time, that specifically apply to the operation, administration, settlement, and oversight of the EIM.

MW: As defined in Central Valley Project's 2025 Marketing Plan, is a unit measuring the rate of production of electricity; one megawatt equals one million watts.

NERC: The North American Electric Reliability Corporation.

New Rate: As defined in WAPA's OATT, means the modification of a Rate for transmission or ancillary services provided by the Transmission Provider which has been promulgated pursuant to the rate development process outlined in Power and Transmission Rates, 10 CFR part 903 (2006).

NITS: Network Integration Transmission Service, as defined in WAPA's OATT, is the transmission service provided under Part III of the Tariff.

Non-conforming Load: The term is not officially defined by CAISO at this time and will be addressed in the future. The following description reasonably aligns with the CAISO's use of the term in defining load forecasting requirements under EIM: is the load with unpredictable load pattern, e.g., pumps, industrial plants, etc., that makes it difficult for the CAISO model to accurately forecast. CAISO's load forecasting model uses historical actual conforming load data and meteorological data determined necessary to accurately forecast the conforming load. When non-conforming load causes more than 5% deviation (hourly) from the total actual load, they should be modeled separately from the load that CAISO will forecast for the EIM Entity (the conforming load). This requirement is part of the EIM Readiness Criteria in accordance with CAISO Tariff section 29.2(b)(7)(A)(iv).

Non-Firm Point-To-Point Transmission Service: As defined in the Tariff, is Point-To-Point Transmission Service under the Tariff that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in Section 14.7 under Part II of the Tariff. Non-Firm Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month. The Transmission provider may offer Non-Firm Point-To-Point Transmission Service for periods longer than one month. If offered, the terms and conditions will be consistent with Part II of the Tariff and will be posted on the Transmission Provider's OASIS.

OASIS: As defined in WAPA's OATT, is Open Access Same-Time Information System. The information system and standards of conduct contained in Part 37 of FERC's regulations and all additional requirements implemented by subsequent FERC orders dealing with OASIS.

OATT: The Open Access Transmission Tariff or 'OATT', including all schedules or attachments thereto, of the Transmission Provided as amended from time to time, and approved by the Commission.

OM&R: Operation, Maintenance, and Replacements expense refers to the annual expense incurred for attending/servicing/replacement of power and transmission lines and facilities.

Preference: As defined in Central Valley Project's 2025 Marketing Plan, is the requirements of Reclamation Law that provide for preference in the sale of Federal power be given to certain entities, such as governments (state, Federal and Native American), municipalities and other public corporations or agencies, and cooperatives and other nonprofit organizations financed in whole or in part by loans made pursuant to the Rural Electrification Act of 1936 (*See, e.g.,* Reclamation Project Act of 1939, Section 9(c), 43 U.S.C. 485h(c)).

Point-To-Point Transmission Service: As defined in WAPA's OATT, is the reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under Part II of the Tariff.

Project Use: As defined in Central Valley Project's 2025 Marketing Plan, is power as defined by Reclamation Law and/or used to operate CVP and Washoe Project facilities.

Power: As defined in Central Valley Project's 2025 Marketing Plan, is capacity and energy.

Provisional Formula Rates: The formula rates confirmed, approved, and placed into effect on an interim basis by the Deputy Secretary of Energy or his designee.

PRR: Power Revenue Requirement is revenue required by the PRS to recover annual expenses (such as operation and maintenance, purchase power, transmission service expenses, interest, and deferred expenses) and repay Federal investments and other assigned costs.

PRS: Power Repayment Study, as defined in DOE Order RA 6120.2 and used for the rate adjustment period, is a tool used to determine if the projected power revenue for each project is adequate to meet the annual revenue requirement. The PRS is used to calculate how much revenue is needed to meet annual investment obligations, O&M expenses, and repayment requirements (including repayment periods).

Rate: As defined in WAPA's OATT, means the monetary charge or the formula for computing such a charge for any electric service provided a Transmission Provider as defined in 10 CFR part 903.

Rate Adjustment: As defined in WAPA's OATT, means a change in an existing rate or rates, or the establishment of a rate or rates for a new service. It does not include a change in rate schedule provisions or in contract terms, other than changes in the price per unit of service, nor does it include changes in the monetary charge pursuant to a formula stated in a rate schedule or a contract as defined in 10 CFR part 903.

Rate Formula Adjustment: As defined in WAPA's OATT, means a change in an existing rate formula, or the establishment of a rate formula for a new service. It does not include updates to the monetary charge pursuant to a formula stated in a rate schedule or a contract.

Rate Brochure: A document prepared for public distribution explaining the rationale and background for the information contained in this rate order.

Reclamation: United States Department of the Interior; Bureau of Reclamation, and formerly the United States Reclamation Service.

Reclamation Law: As defined in WAPA's 2025 Marketing Plan, refers to a series of Federal laws with a lineage dating back to the late 1800s. Viewed as a whole, those laws create the framework under which WAPA markets CVP power.

Regulation: As defined in CAISO's Tariff, is the service provided either by resources certified by the CAISO as equipped and capable of responding to the CAISO's direct digital control signals, or by System Resources that have been certified by the CAISO as capable of delivering such service to the CAISO BAA, in an upward and downward direction to match, on a Real-Time basis, Demand and resources, consistent with established NERC and WECC reliability standards and any requirements of the Nuclear Regulatory Commission, or its successor. Regulation is used to control the operating level of a resource within a prescribed area in response to a change in system frequency, tie line loading, or the relation of these to each other so as to maintain the target system frequency and/or the established Interchange with other BAAs within the predetermined Regulation Limits. Regulation includes both an increase in Energy production by a resource or decrease in Energy consumption by a resource (Regulation Up) and a decrease in Energy production by a resource or increase in Energy consumption by a resource (Regulation Down). Regulation Up and Regulation Down are distinct capacity products, with separately stated requirements and Ancillary Service Marginal Pricings in each Settlement Period.

Resource Sufficiency: CAISO defines and proposes resource sufficiency evaluation require **all BAAs offer sufficient resources to meet their bid-in demand, reliability capacity to meet forecasted net load**, provide ramp capability to meet their 24-hour net demand variation, and their forecasted ancillary service and imbalance reserve requirements (adjusted for diversity benefit).

Short-Term Firm Point-To-Point Transmission Service: As defined in WAPA's OATT, is Firm Point-To-Point Transmission Service under Part II of the Tariff with a term of less than one year.

SBAA: As defined in WAPA's OATT, is Sub-Balancing Authority Area. An electric power system operating within a host BAA that is bounded by meters and is responsible for BAA-like performance of generation, load, and transmission. WAPA-SN is an SBAA within the BANC BAA.

Tariff: As defined in WAPA's OATT, is the Open Access Transmission Tariff or 'OATT', including all schedules or attachments thereto, of the Transmission Provided as amended from time to time, and approved by the Commission.

TO:	As defined in WAPA's OATT, means Transmission Owner and is the entity that owns, leases or otherwise possesses an interest in the portion of the Transmission System at the Point of Interconnection and may be a Party to the Small Generator Interconnection Agreement to the extent necessary.
Transmission Customer:	As defined in WAPA's OATT, is any Eligible Customer (or its Designated Agent) that (i) executes a Service Agreement, or (ii) requests in writing that the Transmission Provider provide transmission service without a Service Agreement, pursuant to section 15.3 of the Tariff. This term is used in the Part I Common Service Provisions to include customers receiving transmission service under Part II and Part III of this Tariff.
Transmission Provider:	As defined in WAPA's OATT, is the Regional Office of the WAPA that owns, controls, or operates the facilities used for the transmission of electric energy in interstate commerce and provides transmission service under the Tariff.
Transmission System:	As defined in WAPA's OATT, is the facilities owned, controlled, or operated by the Transmission Provider that are used to provide transmission service under Part II and Part III of the Tariff.
UIE:	As defined in WAPA's OATT, Attachment S, is Uninstructed Imbalance Energy. Settlement charges incurred by the Transmission Provider on behalf of Transmission Customers due to uninstructed deviations of supply or demand.
WAPA:	United States Department of Energy, Western Area Power Administration.
WAPA-SN:	United States Department of Energy, Western Area Power Administration, Sierra Nevada Region.
WECC:	The Western Electricity Coordinating Council.

Appendix F – Compliance with Legal and Regulatory Requirements

Legal Authority

Existing DOE procedures for public participation in power and transmission rate adjustments (10 CFR part 903) were published on September 18, 1985, and February 21, 2019. The proposed action is a major rate adjustment, as defined by 10 CFR 903.2(d). In accordance with 10 CFR 903.15(a) and 10 CFR 903.16(a), Sierra Nevada Region will hold public information and public comment forums for this rate adjustment. Sierra Nevada Region will review and consider all timely public comments at the conclusion of the consultation and comment period and adjust the proposal as appropriate. The rates will then be approved on an interim basis.

WAPA is establishing the formula rates for COTP, PACI, CVP transmission, WAPA power, and related services in accordance with section 302 of the DOE Organization Act (42 U.S.C. 7152).

By Delegation Order No. S1-DEL-RATES-2016, effective November 19, 2016, the Secretary of Energy delegated: (1) the authority to develop power and transmission rates to the WAPA Administrator; (2) the authority to confirm, approve, and place such rates into effect on an interim basis to the Deputy Secretary of Energy; and (3) the authority to confirm, approve, and place into effect on a final basis, or to remand or disapprove such rates, to FERC. By Delegation Order No. S1-DEL-S3-2022-2, effective June 13, 2022, the Secretary of Energy also delegated the authority to confirm, approve, and place such rates into effect on an interim basis to the Under Secretary for Infrastructure. By Redelegation Order No. S3-DEL-WAPA1-2023, effective April 10, 2023, the Under Secretary for Infrastructure further redelegated the authority to confirm, approve, and place such rates into effect on an interim basis to WAPA's Administrator.

Availability of Information

All brochures, studies, comments, letters, memorandums, or other documents that Sierra Nevada Region initiates or uses to develop the proposed formula rates are available for inspection and copying at the Sierra Nevada Region located at Western Area Power Administration, 114 Parkshore Drive, Folsom, California 95630. Many of these documents and supporting information are also available on WAPA's website at: [Rate Case 2024 WAPA 207 – Western Area Power Administration]

Ratemaking Procedure Requirements

Environmental Compliance

WAPA is in the process of determining whether an environmental assessment or an environmental impact statement should be prepared or if this action can be categorically excluded from those requirements.

Determination Under Executive Order 12866

WAPA has an exemption from centralized regulatory review under Executive Order 12866; accordingly, no clearance of this notice by the Office of Management and Budget is required.