Colorado Springs Utilities
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2026
Rate Case

September 9, 2025

EXECUTIVE

SUMMARY

Rate Case Filing Summary

Colorado Springs Utilities (Utilities) is submitting a 2026 Rate Case. This filing proposes changes to Electric Rate Schedules, Utilities Rules and Regulations (URR), the Open Access Transmission Tariff (OATT), and proposes a Transmission Owner Filing pursuant to anticipated membership in the Southwest Power Pool (SPP) Regional Transmission Organization (RTO). Please refer to the applicable service specific Reports, Resolutions, Tariff sheets, Worksheets, and Transmission Owner Formula Rate Tables for details.

ELECTRIC

Electric

Report

Electric Service

Colorado Springs Utilities (Utilities) engages in the production, purchase, and distribution of electricity. These activities incur fuel related (production and purchases) and non-fuel related (production and distribution) expenditures. Fuel related expenditures are currently recovered through the Electric Cost Adjustment (ECA) and Electric Capacity Charge (ECC). Non-fuel related expenditures are recovered through Access and Facilities Charges and Demand Charges. This filing proposes changes to the Electric Rate Schedules and procedural actions related to the Public Utility Regulatory Policy Act (PURPA).

1. Industrial Service – Large Load Tariff (ELL)

Electric demands from prospective large load customers present significant challenges for Utilities' infrastructure, resources, planning, and financial position. Utilities proposes the addition of a new large load rate schedule applicable to industrial customers with loads greater than 10MW to advance and balance the principles of:

- Supporting economic development and rate competitiveness.
- Ensuring resource and infrastructure adequacy.
- Minimize cost shifting to existing customers.
- Mitigate stranded cost risk.
- Protect Utilities' financial health.

Utilities coordinated with an industry leading firm to survey and analyze electric utility trends in large load tariff and rate design development. Utilities' proposed rate schedule incorporates best practices including, but not limited to the following considerations:

- Minimum 10-year initial contract period.
- Customer responsibility for the cost of infrastructure extension and/or modifications.
- Service subject to applicable studies, conditions, and resulting cost to:
    - Utilities.
    - Regional Transmission Organization.
- Interim service through Purchase Power Agreement (PPA) until resource adequacy is obtained.
- Bill components include:
    - Access and Facilities Charge, per day.
    - Demand Charge, per kW, per day.
    - System Support Charge, per kW, per day.
    - Resource Adequacy Charge, per kW, per day.
    - Pass through PPA charges, per kWh and/or per kW, per day.

    - Electric Cost Adjustment (ECA), per kWh.
    - Electric Capacity Charge (ECC), per kWh.
    - All other applicable charges.
- Minimum Monthly Bill based on all applicable bill components and the highest of:
    - Billing period maximum demand and energy, or
    - Contracted demand and energy requirements, or
    - 100% of maximum 12-month demand and billing period energy.
- Collateral requirement of cash or letter of credit equal to 36 months of estimated Minimum Monthly Bills.
- After the initial term, contract will automatically renew for an additional 36 months unless customer provides notice to request termination.
- Late payment fee of 1.5% per month will be assessed on overdue balances.

Utilities proposes establishing the Access and Facilities, per day, and the Demand Charge, per kW, per day, equal to the Industrial Service – Large Power and Light (ELG) charges as supported by the 2025 Electric Cost of Service Study included in the 2025 Rate case approved by City Council on November 12, 2024.

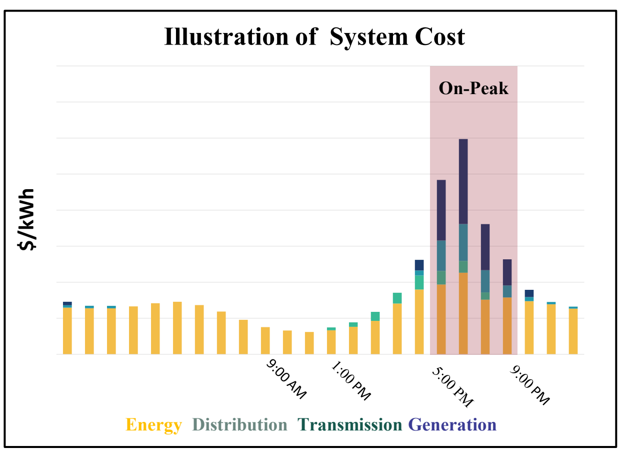
Utilities' ability to provide service to large loads may require interim service through PPAs. If PPAs are required for interim service, the full cost of PPA energy, capacity, and deliverability will be passed through to the customer as specified by contract in lieu of ECA and ECC charges. When interim service through PPAs is no longer necessary, the ECA and ECC will be applicable.

When interim service through PPAs is required, customers will be subject to the System Support Charge and the Resource Adequacy Charge for a period of 10 years. The proposed System Support Charge is designed to mitigate risk associated with serving large loads and to insulate existing customers from potential added costs. The System Support Charge is calculated at 10% of the Demand Charge, per kW, per day. The proposed Resource Adequacy Charge, per kW, per day, is based on preliminary projections of the Cost Of New Energy (CONE) as part of Utilities' Electric Integrated Resource Plan currently in progress. The 10-year period of applicability for the System Support Charge and Resource Adequacy Charge provides a reasonable period of marginal cost recovery for Utilities to plan and acquire adequate resources to service the large load customer while mitigating risk to existing customers.

2. Net Metering

a. Background

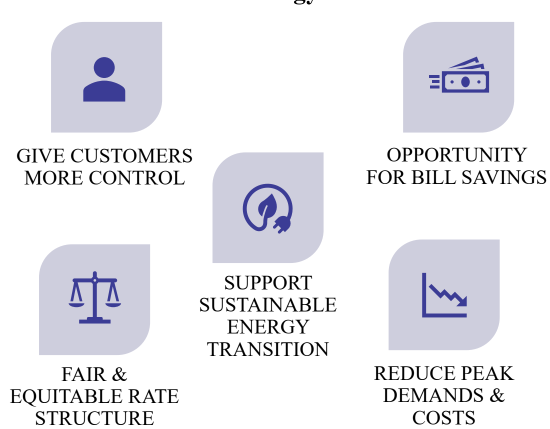
The energy future is transforming, and Utilities has been working over the past few years to assess its resource portfolio with respect to energy regulations, customer growth, and system efficiency. Utilities continues to see customer growth and increased demand on its system and generation portfolio. To meet the increasing number of stringent state requirements and the needs of a growing community, Utilities initiated the development of an Electric rate design strategy in 2018. Over the course of the last eight years, this strategy was developed with Utilities Board guidance and coordinated with Utilities' energy vision workshops, integrated resource planning efforts, and major metering and billing system project implementation. Utilities' draft proposal builds upon the Energy-Wise rates strategy to improve alignment of customer demand with the cost of providing service.



Energy-Wise rates better reflect Utilities' time-varying cost of providing service while offering both system and customer benefits.

Energy-Wise rates are expected to play a significant role in helping reduce high demand and delaying the need to build additional sources of electric generation. With the Energy-Wise rates, most customers will pay different rates for the electricity based on the time of day it is used. This approach more equitably recovers the cost to provide service, while also playing a significant role in incentivizing customers to shift electric use to periods when demand is lower and the cost of providing electricity is cheaper. These rates give customers more control over their bill since they can shift electricity use to less costly time periods. Shifting some electric use to non-peak hours also supports Utilities' sustainable energy transition.

Benefits of Energy-Wise Rates



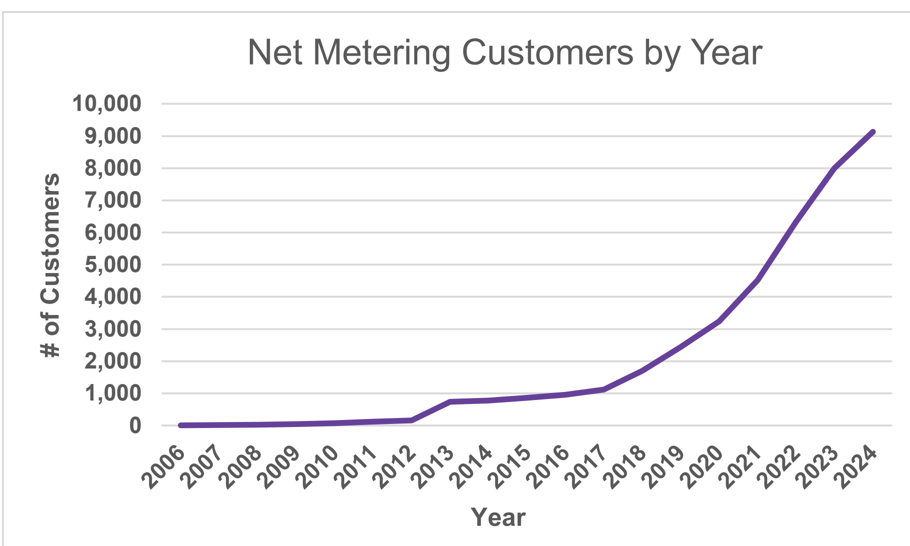
Recent investment in smart meters and customer information systems enable Utilities to make Energy-Wise rate options available to most customers. In 2024, Utilities proposed Energy-Wise rate changes effective October 1, 2025. Utilities expects to transition all existing customers to Energy-Wise rates by early 2026. Due to the unique interaction net metering customers have with Utilities' electric system, the Energy-Wise rates available to most customers do not adequately reflect the cost of providing service to customers with solar behind the meter. As such, net metering customers were not included in the 2025 transition to the Energy-Wise rates. Through 2024 and into 2025, Utilities continued its evaluation and analysis of the most appropriate and fair rate design for net metering customers.

b. Photovoltaic Cost and Net Metering

In 2004, Colorado adopted renewable energy net metering standards. Colorado Revised Statues (CRS) 40-2-124 establish net metering standards for municipal utilities including:

- Treatment of excess monthly and annual generation in kWh.
- Nondiscriminatory rate requirements.
- Interconnection standards.
- Size specifications for customer system.

Utilities first established net metering service in 2005 as a pilot program with availability limited to 50 residential customers. In 2007, the limitation on the number of participating customers was removed and the service became available as a regular service option to residential and commercial customers. Over the last 20 years, the photovoltaic market has matured and costs have significantly decreased. With the reduced cost, the number of net metering interconnections has steadily increased, with more than approximately 1,000 new



interconnections per year in recent years and more than 9,000 total customers' electric service being net metered in 2025. The chart above summarizes the number of net metering customers by year.

The decrease in photovoltaic cost has also supported Utilities in integrating renewable energy resources to our energy portfolio, including the Pike Solar array which features 175 MW of solar energy. After adding Pike Solar to the existing solar, wind and hydro resources, renewable energy is estimated to represent about 27% of our energy portfolio.

c. Net Metering System Interaction

As defined in Colorado Revised Statues (CRS) 40-2-124, energy generated by customer solar systems under net metering service is netted against customer consumption on a monthly billing period basis. Additionally, if monthly solar generation exceeds the customer's monthly consumption, the excess generation credits are rolled forward to the subsequent months and offset future consumption. Netting customer generation and customer consumption on a monthly basis under-quantifies the amount of energy the customer is consuming from Utilities' system and under-quantifies the amount of energy the customer pushes onto Utilities' system. Specifically, for a typical net metering customer, customer consumption exceeds customer generation during the early AM hours, resulting in consumption from the Utilities' system (imports). During the middle of the day, when solar generation is highest, customer generation exceeds consumption and energy is pushed back onto Utilities' system (exports). As customer consumption increases in the afternoon and into the evening and customer generation decreases, customer consumption once again exceeds customer generation resulting in additional consumption, or imports, from the Utilities' system.

As illustrated in Table 1 below, on the randomly selected 24-hour period, the sample net metering customer generated a total of 17 kWh (column c) and consumed a total to 30 kWh (column d). Utilizing a daily basis of net metering, the customer would be charged 13 kWh (column g) representing the net difference between consumption and generation. However, as depicted by columns e and f, the customer consumed, or imported, 17 kWh from Utilities' system, and pushed, or exported, 5 kWh back onto Utilities' system. For this sample daily period, net metering under-quantified the customer's consumption from Utilities' system by 4 kWh. Extrapolated over the course of a month or year, the under-quantification of imports and exports can result in significant cost shifting to other non-net metering customers within the rate class.

Table 1: Illustration of Hourly Generation and Consumption

Line No (a)	Hour (b)	Gen (c)	Cons (d)	Import (e)	(Export) (f)	Net Import / (Export) (g)
1	1	0.00	1.05	1.05	-	1.05
2	2	0.00	0.95	0.95	-	0.95
3	3	0.00	0.91	0.91	-	0.91
4	4	0.00	0.85	0.85	-	0.85
5	5	0.00	0.84	0.84	-	0.84
6	6	0.00	0.87	0.87	-	0.87
7	7	0.09	1.06	0.97	-	0.97
8	8	0.47	1.16	0.69	-	0.69
9	9	1.10	1.22	0.12	-	0.12
10	10	1.79	1.20	-	(0.59)	(0.59)
11	11	2.34	1.26	-	(1.09)	(1.09)
12	12	2.44	1.28	-	(1.16)	(1.16)
13	13	2.28	1.31	-	(0.97)	(0.97)
14	14	2.00	1.39	-	(0.61)	(0.61)
15	15	1.55	1.38	-	(0.18)	(0.18)
16	16	1.32	1.42	0.10		0.10
17	17	0.98	1.49	0.51		0.51
18	18	0.65	1.60	0.95		0.95
19	19	0.34	1.66	1.32		1.32
20	20	0.09	1.62	1.53		1.53
21	21	0.01	1.61	1.60		1.60
22	22	0.00	1.62	1.62		1.62
23	23	0.00	1.48	1.48		1.48
24	24	0.00	1.17	1.16		1.16
25	**Total**	**17.48**	**30.37**	**17.49**	**(4.60)**	**12.89**

d. Net Metering Subsidy

Current rate designs applicable to residential and commercial net metering customers recover capacity cost through energy charges, which compounds the cost shifting to non-net metering customers that results from under-quantification of energy consumed from Utilities' system. Although some level of intraclass cross subsidization is a reality with any rate design, for non-net metering customers, recovery of capacity cost through energy charges can reasonably reflect the cost of providing service. Energy-Wise rates, which were approved by City Council in 2024 and go into effect in October 2025, further improve the reasonableness and fairness of cost recovery as capacity costs can be more accurately allocated to the on-peak energy charge. Due to the monthly basis of net metering, Time-of-Day (TOD) rates do not adequately reflect the cost to provide service to net metering customers, as generation and consumption are netted within and/or across on-peak and off-peak periods.

Further analysis to quantify the net metering subsidy related to Utilities net metering customers was conducted using the cost-of-service approach (Sergici et al, 2019)[1]. Based on the cost-of-service analysis, the median customer subsidy for a Utilities net metering customer is approximately $600 annually or $50 per month. This level of subsidy is consistent with results of similar studies across the United States, with subsidies ranging from $20 to $100 per month (Sergici et al, 2019)[1]. All net metering customers are unique in terms of usage and system size, and therefore the $600 is not reflective of every customer. However, the median customer is representative of a typical net metering customer and can be used to estimate overall subsidy levels. Utilizing the $600 median subsidy, when attributed to over 9,000 net metering customers, the total cost shift from net metering customers to non-net metering customers is estimated to exceed $5,500,000 annually.

e. Energy-Wise Net Metering Rate Options

To promote fair and equitable cost recovery and to align rates with the cost of providing service in the transformed electric landscape, Utilities proposes the addition of net metering rate options applicable to residential and commercial net metering customers, effective January 1, 2027. The proposed rates are supported by the 2025 Electric Cost of Service Study included in the 2025 Rate case approved by City Council on November 12, 2024. The proposed rate options include:

- Access and Facilities, per day charges based on costs classified and allocated as customer cost in the Line – Secondary, Electric Service, Meters and Installations, and customer functions.
- Access and Facilities, per kWh charges based on costs classified and allocated as Energy cost in the Generation Non-Fuel, Transmission, and Surplus Payments to the City functions.
- Demand Charge, per kW, per day charge based on costs classified and allocated as Demand cost in the Generation Non-Fuel, Transmission, Substation, Line – Primary,

[1] Sergici, S., Yang, Y., Castaner, M., Faruqui, A. (2019). Quantifying net energy metering subsidies. The Electricity Journal. Volume 32, Issue 8. https://www.sciencedirect.com/science/article/abs/pii/S1040619019301861#preview-section-abstract

and Line – Secondary functions. The demand determination for the proposed Demand Charge is the greatest 15-minute net load during On-Peak hours in the billing period.

- ECA, per kWh.
- ECC, per kWh.

Utilities proposes to migrate all residential and commercial net metering customers from frozen rate options to the new proposed net metering rate options effective January 1, 2027. Industrial and contract service Energy-Wise rate options currently include appropriate demand charges. As a result, additional net metering options are not necessary for industrial and contract service net metering customers. Utilities proposes to migrate any industrial net metering customers receiving service under frozen rate options to the Energy-Wise standard rate options effective January 1, 2027.

Municipal Utilities are protected by Articles V, XI, XX, and XXV of the Colorado Constitution, which include protections in matters of rate making and billing. Utilities is a municipal utility operated as an Enterprise of the City of Colorado Springs and the City Council's authority to establish rates, charges, and regulations for utility services is contained within the Colorado Constitution, Colorado Statutes, the Colorado Springs Charter, the City Code, and City Council's Rules and Procedures.

The proposed net metering rate options are designed consistent with CRS 40-2-124. Utilities proposed rate options have a rational nexus to the cost of providing service to net metering customers, and as a result are just, reasonable, and non-discriminatory.

3. Contract Service – Military Wheeling (ECW)

The Department of Defense (DoD) receives retail service for the majority of their loads under Utilities' Contract Service – Military (ECD) Rate Schedule. The Contract Service – Military Wheeling (ECW) Rate Schedule is available to the DoD for the purpose of wheeling hydro power from the Western Area Power Administration (WAPA) and the Southeastern Colorado Water Conservancy District over Utilities distribution system. The DoD load served under the ECW Rate Schedule represents less than 14% of the overall average DoD monthly load. Historically, the wheeling service over Utilities' transmission system has been billed under Utilities' Open Access Transmission Tariff (OATT) rates and wheeling through Utilities' distribution system has been billed under the ECW rates.

Utilities anticipates joining the Southwest Power Pool (SPP) Regional Transmission Organization (RTO) and upon approved membership into the RTO, Utilities' OATT will be withdrawn in its entirety and utilization of Utilities transmission system will be administered under the SPP RTO's OATT based on Utilities' Transmission Owner Filing materials to SPP.

As a retail customer of Utilities, the DoD has expressed interest in maintaining Utilities' billing treatment for loads served by WAPA energy rather than being considered a transmission customer under SPP's OATT. In support of DoD's position, Utilities anticipates successfully demonstrating to interested parties including, but not limited to, DoD, WAPA, and SPP, that DoD's WAPA energy becomes part of Utilities network load to self under SPP's OATT, and as such is appropriately billed to the DoD under Utilities' proposed ECW rate as described below. Furthermore, if additional transfer of ownership or other administrative action is necessary to demonstrate the appropriateness of retail treatment, Utilities will participate in discussions to develop mutual agreements or transfers to facilitate appropriate treatment under Utilities' Rate Schedules.

To appropriately recover cost of providing wheeling service over both Utilities' transmission and distribution systems, Utilities proposes to modify the ECW rate to include transmission and distribution allocations as supported by the 2025 Electric Cost of Service Study included in the 2025 Rate case approved by City Council on November 12, 2024. The proposed rates result in billing treatment approximately equal to current charges under the current ECW and Utilities's OATT, but consolidate the charges into a single rate component under the ECW Rate Schedule.

4. Other Rate Schedule Clerical Changes or Corrections

Utilities proposes several clerical changes to Electric Rate Schedules to add clarity and/or make administrative corrections. The full detail of proposed changes can be found in the proposed resolution and tariff sheets.

5. Public Utilities Regulatory Policy Act (PURPA)

The federal Public Utilities Regulatory Policies Act (PURPA) was established in 1978 to promote conservation and efficiency in response to the energy crisis of the 1970s. Section 111(a) of PURPA, 16 U.S.C 2621, requires electric utilities to consider each standard established by subsection (d) and make determinations of the appropriateness of implementing such standards.

The 2021 Infrastructure Investment and Jobs Act (IIJA) added two new standards for mandatory consideration under PURPA, Section 111(d). Procedural compliance pursuant to Resolution 180-22 directed Utilities to commence a 12-month consideration period for determining appropriateness of implementing such standards. The two new PURPA standards added pursuant to the IIJA are:

- Demand Response and Demand Flexibility.
    - Promotion of demand response and demand flexibility practices to reduce electricity consumption during periods of unusually high demand.
    - Establishment of rate mechanisms for the timely recovery of the cost of promoting demand response and demand flexibility practices.
- Electric Vehicle (EV) Charging Rates.
    - Promotion of affordable and equitable EV charging options.
    - Improvement of customer experience associated with EV charging.
    - Appropriate recovery of the marginal cost of delivering electricity to EVs and EV charging infrastructure.
    - Acceleration of third-party investment in EV charging.

As detailed in Section 2. Net Metering above, Energy-Wise rates play a significant role in incentivizing customers to shift electric use to periods when demand is lower and cost of providing electricity is cheaper. With Energy-Wise rates, customers pay different rates for electricity based on the TOD it is used, with Utilities' on-peak period defined as 5:00 pm to 9:00 pm weekdays, excluding certain holidays. Energy-Wise becomes effective October 1, 2025, and at that time the Energy-Wise Standard TOD rate becomes the standard rate option for most customers. In addition to the Energy-Wise standard rate option, most customers have the ability to select an alternate rate option dependent upon the applicable rate class. A summary of Energy-Wise rate options is shown below.

The Energy-Wise Plus rate option available to most residential, commercial, and industrial customers, includes program components for Critical Peak Period events. Critical Peak Period events can be called by Utilities within On-Peak hours, up to 15 events per year. The Critical Peak Period, per kWh rates promote and timely recover the cost of demand response. In addition to Energy-Wise Plus, Utilities' Industrial Service – Interruptible Rate Schedule provides a demand response mechanism for industrial loads over 500 kW.

Energy Wise Rate Options			
Customer Type	**Energy Wise (Standard TOD)**	**Energy Wise Plus (Optional TOD)**	**Fixed Seasonal (Optional anytime rate)**
Residential & Small Commercial	✓	✓	✓
Medium & Large Commercial	✓	✓	
Industrial & Contract Service	✓	✓	
	TOD periods provide Customers opportunities to control and reduce their bill by shifting a portion of their energy usage to the Off-Peak period	Additional opportunities for Customer bill control and savings by shifting energy usage to the Off-Peak and Off-Peak Saver periods and reducing usage during Critical Peak Events	Opportunities for reduced bill fluctuation from month to month with enhanced Access and Facilities per Day charges and fixed seasonal energy rates

Utilities' commercial and industrial rate classes are appropriately defined based on customer maximum demand and Energy-Wise rates are designed to recover energy and infrastructure cost through various demand and energy charges depending on the rate class. Energy-Wise rates provide appropriate options and cost recovery for Electric Vehicle charging. Specifically, Energy-Wise rates provide incentive to charge EV's during Off-Peak periods, and the Energy-Wise Plus rate option provides additional opportunity for affordable EV charging during Off-Peak Saver periods defined as 9:00 am to 1:00 pm daily. In addition to Energy-Wise rates, Utilities provides EV Public Charging Service at several Utilities' locations through TOD rates which further promote customer experience.

Utilities PURPA conclusion and finding is that Utilities approved Electric Rate Schedules demonstrate compliance with the two new standards. As a result, separate adoption of the standard is not necessary and does not provide additional benefit.

Electric

Resolutions

RESOLUTION NO. ________-25

A RESOLUTION SETTING CERTAIN ELECTRIC RATES WITHIN THE SERVICE AREA OF COLORADO SPRINGS UTILITIES AND REGARDING CERTAIN CHANGES TO THE ELECTRIC RATE SCHEDULES

WHEREAS, Utilities has evaluated and found that existing rate schedules do not adequately address the resource adequacy, infrastructure requirements, risks, and costs of providing service to large industrial loads; and

WHEREAS, Utilities, proposed to freeze participation in the Industrial Service – Time-of-Day Transmission Voltage (ETX) Rate Schedule; and

WHEREAS, Utilities proposed to implement the addition of Industrial Service – Large Load (ELL) Rate Schedule applicable to industrial customers with loads greater than 10MW; and

WHEREAS, Utilities is implementing Energy-Wise rates to address changes in regulations, energy transitions, new metering technology, and growth in the community; and

WHEREAS, Residential, Commercial, and some Industrial customers currently receive Net Metering Service under frozen rate schedules; and

WHEREAS, Utilities' frozen rate schedules do not adequately recover the cost of providing Net Metering service; and

WHEREAS, Utilities proposed to modify the Net Metering program and add the Energy-Wise Net Metering rate options for Residential and Commercial customer classes; and

WHEREAS, Utilities proposed moving Residential and Commercial customers receiving service under the Net Metering Rate Schedule to the applicable Energy-Wise Net Metering rate options; and

WHEREAS, Utilities proposed moving Industrial customers receiving service under the Net Metering Rate Schedule to the applicable Energy-Wise standard options; and

WHEREAS, Utilities proposed revising the Contract Service – Military Wheeling (ECW) Rate Schedule to shift transmission expense recovery from the Open Access Transmission Tariff (OATT) to ECW non-fuel rates, reflecting costs for transmission wheeling service as Utilities will no longer maintain its independent OATT in conjunction with planned membership in joining the Southwest Power Pool Regional Transmission Organization; and

WHEREAS, Utilities proposed administrative changes removing the Fixed Seasonal Options (ETR-F, ECS-F) as exceptions to availability under the Community Solar Garden Program and updating the reference lettering order to reflect those exception removals; and

WHEREAS, Utilities proposed to make other clerical modifications; and

WHEREAS, Utilities proposed to make the Electric Rate Schedule and tariff changes effective January 1, 2026, April 1, 2026, and for changes related to the Energy-Wise Net Metering program, January 1, 2027; and

WHEREAS, the details of the changes noted above are reflected in Utilities' 2026 Rate Case; and

WHEREAS, the City Council finds Utilities' proposed modifications prudent; and

WHEREAS, the City Council finds that the proposed modifications to the Electric Rate Schedules and tariffs are just, reasonable, sufficient and not unduly discriminatory and allow Utilities to collect revenues that enable Utilities to continue to operate in the best interest of all of its Customers; and

WHEREAS, Utilities provided public notice of the proposed changes and has complied with the requirements of the City Code for changing its electric schedules; and

WHEREAS, specific rates, policy changes, and changes to any terms and conditions of service are set out in the attached tariffs for adoption with the final City Council Decision and Order in this case.

NOW, THEREFORE, BE IT RESOLVED BY THE CITY COUNCIL OF THE CITY OF COLORADO SPRINGS:

Section 1. That Colorado Springs Utilities Tariff, City Council Volume No. 6, Electric Rate

Schedules shall be revised as follows:

Effective January 1, 2026

City Council Vol. No. 6		
Sheet No.	**Title**	**Cancels Sheet No.**
Sixth Revised Sheet No.1	TABLE OF CONTENTS	Fifth Revised Sheet No.1
Second Revised Sheet No. 2.19	RATE TABLE	First Revised Sheet No. 2.19
Second Revised Sheet No. 2.20	RATE TABLE	First Revised Sheet No. 2.20
Original Sheet No. 2.21	RATE TABLE	
Original Sheet No. 2.22	RATE TABLE	
Original Sheet No. 2.23	RATE TABLE	
Fourth Revised Sheet No. 3	GENERAL	Third Revised Sheet No. 3
Fourth Revised Sheet No. 3.1	GENERAL	Third Revised Sheet No. 3.1
First Revised Sheet No. 5.2	COMMERCIAL SERVICE – SMALL (ECS, ECS-P, ECS-F)	Original Sheet No. 5.2
Second Revised Sheet No. 9	INDUSTRIAL SERVICE – 4,000 kW MINIMUM (E8S, E8S-P)	First Revised Sheet 9
Third Revised Sheet No. 10	INDUSTRIAL SERVICE – LARGE POWER AND LIGHT (ELG, ELG-P)	Second Revised Sheet No. 10
First Revised Sheet No. 11	FROZEN INDUSTRIAL SERVICE – TIME-OF-DAY TRANSMISSION VOLTAGE (ETX)	Original Sheet No. 11
Second Revised Sheet No. 23	COMMUNITY SOLAR GARDEN PROGRAM	First Revised Sheet No. 23
Original Sheet No. 27	INDUSTRIAL SERVICE – LARGE LOAD (ELL)	
Original Sheet No. 27.1	INDUSTRIAL SERVICE – LARGE LOAD (ELL)	
Original Sheet No. 27.2	INDUSTRIAL SERVICE – LARGE LOAD (ELL)	
Original Sheet No. 27.3	INDUSTRIAL SERVICE – LARGE LOAD (ELL)	
Original Sheet No. 27.4	INDUSTRIAL SERVICE – LARGE LOAD (ELL)	

Effective April 1, 2026

City Council Vol. No. 6		
Sheet No.	**Title**	**Cancels Sheet No.**
Second Revised Sheet No. 2.13	RATE TABLE	First Revised Sheet No. 2.13
Second Revised Sheet No. 13	CONTRACT SERVICE – MILITARY WHEELING (ECW)	First Revised Sheet No. 13
First Revised Sheet No. 13.1	CONTRACT SERVICE – MILITARY WHEELING (ECW)	Original Sheet No. 13.1

Effective January 1, 2027

City Council Vol. No. 6		
Sheet No.	**Title**	**Cancels Sheet No.**
Seventh Revised Sheet No.1	TABLE OF CONTENTS	Sixth Revised Sheet No.1
Sixth Revised Sheet No. 2.1	RATE TABLE	Fifth Revised Sheet No. 2.1
Fourth Revised Sheet No. 2.3	RATE TABLE	Third Revised Sheet No. 2.3
Sixth Revised Sheet No. 2.5	RATE TABLE	Fifth Revised Sheet No. 2.5
Fourth Revised Sheet No. 2.6	RATE TABLE	Third Revised Sheet No. 2.6
Third Revised Sheet No. 2.20	RATE TABLE	Second Revised Sheet No. 2.20
Fifth Revised Sheet No. 3	GENERAL	Fourth Revised Sheet No. 3
First Revised Sheet No. 3.3	GENERAL	Original Sheet No. 3.3
First Revised Sheet No. 3.4	GENERAL	Original Sheet No. 3.4
Second Revised Sheet No. 4	RESIDENTIAL SERVICE (E1R, ETR, ETR-P, ETR-F, ERNM)	First Revised Sheet No. 4
Second Revised Sheet No. 5	FROZEN COMMERCIAL SERVICE – SMALL (E1C)	First Revised Sheet No. 5
Second Revised Sheet No. 5.2	COMMERCIAL SERVICE – SMALL (ECS, ECS-P, ECS-F, ECSNM)	First Revised Sheet No. 5.2
Second Revised Sheet No. 6	FROZEN COMMERCIAL SERVICE – GENERAL (E2C, ETC)	First Revised Sheet No. 6
First Revised Sheet No. 6.1	COMMERCIAL SERVICE – MEDIUM 10 kW MINIMUM (ECM, ECM-P, ECMNM)	Original Sheet No. 6.1
First Revised Sheet No. 6.2	COMMERCIAL SERVICE – LARGE 50 kW MINIMUM (ECL, ECL-P, ECLNM)	Original Sheet No. 6.2
Third Revised Sheet No. 7	FROZEN INDUSTRIAL SERVICE – 1,000 kWh/DAY MINIMUM (ETL, ETLO, ETLW)	Second Revised Sheet No. 7
First Revised Sheet No. 7.1	INDUSTRIAL SERVICE – 100 kW MINIMUM (EIS, EIS-P)	Original Sheet No. 7.1
Second Revised Sheet No. 8	INDUSTRIAL SERVICE – 500 kW MINIMUM (E8T, E8T-P)	First Revised Sheet No. 8
Third Revised Sheet No. 9	INDUSTRIAL SERVICE – 4,000 kW MINIMUM (E8S, E8S-P)	Second Revised Sheet No. 9
Fourth Revised Sheet No. 10	INDUSTRIAL SERVICE – LARGE POWER AND LIGHT (ELG, ELG-P)	Third Revised Sheet No. 10
Third Revised Sheet No. 12	CONTRACT SERVICE – MILITARY (ECD, ECD-P, EHYDPWR, EINFPRS)	Second Revised Sheet No. 12
Fourth Revised Sheet No. 20	NET METERING	Third Revised Sheet No. 20
Third Revised Sheet No. 20.1	NET METERING	Second Revised Sheet No. 20.1
Third Revised Sheet No. 23	COMMUNITY SOLAR GARDEN PROGRAM	Second Revised Sheet No. 23

Section 2. The attached Tariff Sheets, Council Decision and Order, and other related matters are hereby approved and adopted.

Dated at Colorado Springs, Colorado, this 28th day of October 2025.

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Council President

ATTEST:

____
Sarah B. Johnson, City Clerk

RESOLUTION NO. ________-25

A RESOLUTION ACCEPTING THE CONCLUSIONS AND RECOMMENDATIONS OF THE STAFF OF COLORADO SPRINGS UTILITIES CONCERNING THE INFRASTRUCTURE INVESTMENT AND JOBS ACT OF 2021 STANDARDS AMENDING THE FEDERAL PUBLIC UTILITY REGULATORY POLICIES ACT

WHEREAS, the federal Infrastructure Investment and Jobs (IIJA) Act of 2021 added two new items to the standards section of the federal Public Utility Regulatory Policies Act of 1978 (PURPA) that are to be considered by state public utility commissions, or if a utility is not regulated by a state commission, then the standards are to be considered by a utility's regulatory body; and

WHEREAS, the two new items relate to demand response/demand flexibility and electric vehicle charging rates; and

WHEREAS, PURPA requires a utility's regulatory body to consider the new standards and then make determinations as to whether those standards should be implemented; and

WHEREAS, Colorado Springs Utilities' (Utilities) regulatory body is the City Council of the City of Colorado Springs; and

WHEREAS, the City Council, pursuant to Resolution 180-22, directed the Staff of Utilities to assist in gathering information; and

WHEREAS, the Staff of Utilities gathered information for its review of the two new items to the standards and demonstrated sufficient enterprise compliance with each proposed standard though existing rate schedules, programs, and practices; and

WHEREAS, City Council finds that separately adopting the two new items to the standards is not necessary; and

NOW, THEREFORE, BE IT RESOLVED BY THE CITY COUNCIL OF THE CITY OF COLORADO SPRINGS:

Section 1. City Council hereby determines, after due consideration, public notice, and public comment, to accept the conclusion and recommendation of the Staff of Utilities by not separately adopting the two IIJA standards that amended PURPA.

Section 2. The Resolution shall be in full force and effect immediately upon its adoption

Dated at Colorado Springs, Colorado, this 28th day of October 2025.

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Council President

ATTEST:

____
Sarah B. Johnson, City Clerk

Electric

Redline Tariff Sheets

Effective January 1, 2026

ELECTRIC RATE SCHEDULES

TABLE OF CONTENTS

DESCRIPTION **SHEET NO.**

ELECTRIC RATE SCHEDULES

RATE TABLE

Description	Rates (Note) 2025	2026	2027	2028	2029
Totalization Service – Sheet No. 18					
For each meter totalized, per meter, per day	$8.0000				
Enhanced Power Service – Sheet No. 19					
Reserved Capacity Charge:					
The greater of On-Peak or Off-Peak Billing Demand or projected peak demand, per kW, per day	$0.0333	$0.0355	$0.0378	$0.0403	$0.0429
Operations & Maintenance Charge:					
See *Line Extension and Service Standards* for Electric for calculation.					
~~**Small Power Producers and Cogeneration Service – Sheet No. 21**~~					
~~On-Peak, per kWh~~	~~$0.0195~~				
~~Off-Peak, per kWh~~	~~$0.0180~~				
~~**Community Solar Garden Bill Credit (Pilot Program) – Sheet No. 22**~~					
~~The rate applicable to each kilowatt hour under the Bill Credit section of this rate schedule~~	~~$0.1080~~	~~$0.1150~~	~~$0.1225~~	~~$0.1305~~	~~$0.1390~~
~~**Community Solar Garden Program – Sheet No. 23**~~					
~~**Customer Rate Class – Credit, per kWh**~~					
~~Residential Service (E1R, ETR, ETR-F)~~	~~$0.0654~~	~~$0.0697~~	~~$0.0742~~	~~$0.0790~~	~~$0.0841~~
~~Commercial Service – Small (E1C)~~	~~$0.0585~~	~~$0.0623~~	~~$0.0663~~	~~$0.0706~~	~~$0.0752~~
~~Commercial Service – Small (ECS, ECS-F)~~	~~$0.0591~~	~~$0.0629~~	~~$0.0670~~	~~$0.0714~~	~~$0.0760~~
~~Commercial Service – General (E2C)~~	~~$0.0586~~	~~$0.0624~~	~~$0.0665~~	~~$0.0708~~	~~$0.0754~~
~~Commercial Service – General Time-of-Day Option (ETC)~~	~~$0.0586~~	~~$0.0624~~	~~$0.0665~~	~~$0.0708~~	~~$0.0754~~
~~Commercial Service – Medium 10 kW Minimum (ECM)~~	~~$0.0585~~	~~$0.0623~~	~~$0.0663~~	~~$0.0706~~	~~$0.0752~~
~~Commercial Service – Large 50 kW Minimum (ECL)~~	~~$0.0564~~	~~$0.0601~~	~~$0.0640~~	~~$0.0682~~	~~$0.0726~~
~~Industrial Service – 1,000 kWh/Day Minimum (ETL)~~	~~$0.0541~~	~~$0.0576~~	~~$0.0613~~	~~$0.0653~~	~~$0.0695~~
~~Industrial Service – 100 kW Minimum (EIS)~~	~~$0.0549~~	~~$0.0585~~	~~$0.0623~~	~~$0.0663~~	~~$0.0706~~
~~Industrial Service – 500 kW Minimum (E8T)~~	~~$0.0514~~	~~$0.0547~~	~~$0.0583~~	~~$0.0621~~	~~$0.0661~~

Note: 2025 rates are effective October 1, 2025. All other rates are effective January 1st of the respective year shown. Rates effective 2029 will remain effective until superseded by City Council.

ELECTRIC RATE SCHEDULES

RATE TABLE

~~Description~~	~~Rates (Note)~~				
	~~2025~~	~~2026~~	~~2027~~	~~2028~~	~~2029~~
~~Industrial Service – 4,000 kW Minimum (E8S)~~	~~$0.0507~~	~~$0.0540~~	~~$0.0575~~	~~$0.0612~~	~~$0.0652~~
~~Industrial Service – Large Power and Light (ELG)~~	~~$0.0443~~	~~$0.0472~~	~~$0.0503~~	~~$0.0536~~	~~$0.0571~~
~~Industrial Service – Time-of-Day Transmission Voltage (ETX)~~	~~$0.0578~~	~~$0.0616~~	~~$0.0656~~	~~$0.0699~~	~~$0.0744~~
~~Contract Service – Military (ECD)~~	~~$0.0517~~	~~$0.0551~~	~~$0.0587~~	~~$0.0625~~	~~$0.0666~~
~~Electric Vehicle Public Charging Service – Time-of-Day – Sheet No. 25~~					
~~Level 2~~					
~~On-Peak, per kWh~~	~~$0.3600~~	~~$0.3800~~	~~$0.4000~~	~~$0.4300~~	~~$0.4600~~
~~Off-Peak, per kWh~~	~~$0.1300~~	~~$0.1400~~	~~$0.1500~~	~~$0.1600~~	~~$0.1700~~
~~Idle Rate, per minute~~	~~$0.1100~~	~~$0.1200~~	~~$0.1300~~	~~$0.1400~~	~~$0.1500~~
~~Idle rate is applicable beginning 15 minutes after charge is complete.~~					
~~Direct Current Fast Charger (DCFC)~~					
~~On-Peak, per kWh~~	~~$0.5800~~	~~$0.6200~~	~~$0.6600~~	~~$0.7000~~	~~$0.7500~~
~~Off-Peak, per kWh~~	~~$0.2000~~	~~$0.2100~~	~~$0.2200~~	~~$0.2300~~	~~$0.2400~~
~~Idle Rate, per minute~~	~~$0.3200~~	~~$0.3400~~	~~$0.3600~~	~~$0.3800~~	~~$0.4000~~
~~Idle rate is applicable beginning 15 minutes after charge is complete.~~					
~~Interruptible Service – Sheet No. 26~~					
~~Demand Credit, per kW, per day~~	~~$0.1233~~				
~~Energy Credit, per kWh~~	~~$0.4500~~				

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~~Note: 2025 rates are effective October 1, 2025. All other rates are effective January 1st of the respective year shown. Rates effective 2029 will remain effective until superseded by City Council~~.

ELECTRIC RATE SCHEDULES

RATE TABLE

Description	Rates (Note)				
	2025	**2026**	**2027**	**2028**	**2029**
Small Power Producers and Cogeneration Service – Sheet No. 21					
On-Peak, per kWh	$0.0195				
Off-Peak, per kWh	$0.0180				
Community Solar Garden Bill Credit (Pilot Program) – Sheet No. 22					
The rate applicable to each kilowatt hour under the Bill Credit section of this rate schedule	$0.1080	$0.1150	$0.1225	$0.1305	$0.1390
Community Solar Garden Program – Sheet No. 23					
Customer Rate Class – Credit, per kWh					
Residential Service (E1R, ETR, ETR-F)	$0.0654	$0.0697	$0.0742	$0.0790	$0.0841
Commercial Service – Small (E1C)	$0.0585	$0.0623	$0.0663	$0.0706	$0.0752
Commercial Service – Small (ECS, ECS-F)	$0.0591	$0.0629	$0.0670	$0.0714	$0.0760
Commercial Service – General (E2C)	$0.0586	$0.0624	$0.0665	$0.0708	$0.0754
Commercial Service – General Time-of-Day Option (ETC)	$0.0586	$0.0624	$0.0665	$0.0708	$0.0754
Commercial Service – Medium 10 kW Minimum (ECM)	$0.0585	$0.0623	$0.0663	$0.0706	$0.0752
Commercial Service – Large 50 kW Minimum (ECL)	$0.0564	$0.0601	$0.0640	$0.0682	$0.0726
Industrial Service – 1,000 kWh/Day Minimum (ETL)	$0.0541	$0.0576	$0.0613	$0.0653	$0.0695
Industrial Service – 100 kW Minimum (EIS)	$0.0549	$0.0585	$0.0623	$0.0663	$0.0706
Industrial Service – 500 kW Minimum (E8T)	$0.0514	$0.0547	$0.0583	$0.0621	$0.0661
Industrial Service – 4,000 kW Minimum (E8S)	$0.0507	$0.0540	$0.0575	$0.0612	$0.0652
Industrial Service – Large Power and Light (ELG)	$0.0443	$0.0472	$0.0503	$0.0536	$0.0571
Industrial Service – Time-of-Day Transmission Voltage (ETX)	$0.0578	$0.0616	$0.0656	$0.0699	$0.0744
Contract Service – Military (ECD)	$0.0517	$0.0551	$0.0587	$0.0625	$0.0666

Note: 2025 rates are effective October 1, 2025. All other rates are effective January 1st of the respective year shown. Rates effective 2029 will remain effective until superseded by City Council.

ELECTRIC RATE SCHEDULES

RATE TABLE

Description	Rates (Note)				
	2025	2026	2027	2028	2029
Electric Vehicle Public Charging Service – Time-of-Day – Sheet No. 25					
Level 2					
On-Peak, per kWh	$0.3600	$0.3800	$0.4000	$0.4300	$0.4600
Off-Peak, per kWh	$0.1300	$0.1400	$0.1500	$0.1600	$0.1700
Idle Rate, per minute	$0.1100	$0.1200	$0.1300	$0.1400	$0.1500
Idle rate is applicable beginning 15 minutes after charge is complete.					
Direct Current Fast Charger (DCFC)					
On-Peak, per kWh	$0.5800	$0.6200	$0.6600	$0.7000	$0.7500
Off-Peak, per kWh	$0.2000	$0.2100	$0.2200	$0.2300	$0.2400
Idle Rate, per minute	$0.3200	$0.3400	$0.3600	$0.3800	$0.4000
Idle rate is applicable beginning 15 minutes after charge is complete.					
Interruptible Service – Sheet No. 26					
Demand Credit, per kW, per day	$0.1233				
Energy Credit, per kWh	$0.4500				

Note: 2025 rates are effective October 1, 2025. All other rates are effective January 1st of the respective year shown. Rates effective 2029 will remain effective until superseded by City Council.

ELECTRIC RATE SCHEDULES

RATE TABLE

Description	Rates (Note)			
	2026	2027	2028	2029
Industrial Service – Large Load (ELL) – Sheet No. 27				
Access and Facilities Charge, per day	$8.9065	$9.9664	$11.1524	$12.4795
Demand Charge Secondary, per kW, per day	$0.8593	$0.9616	$1.0760	$1.2040
System Support Charge, per kW, per day	$0.0859	$0.0962	$0.1076	$0.1204
Resource Adequacy Charge, per kW, per day	$0.4110	$0.4377	$0.4662	$0.4965
Purchased Energy Charge, per kWh	By Contract			
Purchased Capacity Charge, per kW, per day	By Contract			
Electric Cost Adjustment (ECA), per kWh	Sheet No. 2.17			
Electric Capacity Charge (ECC), per kWh	Sheet No. 2.18			

Note: All rates are effective January 1st of the respective year shown. Rates effective 2029 will remain effective until superseded by City Council.

DEMAND DETERMINATIONS

Commercial Service (ECM, ECM-P, ECL, ECL-P)

Maximum Demand and/or Billing Demand:

Greatest 15-minute load during any block of time in the billing period.

Industrial and Contract Service

Maximum Demand (ETL, EIS, EIS-P, E8T, E8T-P, E8S, E8S-P, ELG, ELG-P, ETX, ECD, ECD-P, ELL)

Maximum Demand is the greatest 15-minute load during any time in the billing period adjusted upward by 1% for each 1% that the power factor of Customer is below 95% lagging or leading.

Billing Demand

Energy-Wise Standard Time-of-Day Option (ETL, EIS, E8T, E8S, ELG, ETX, ECD)

On-Peak:

The greatest 15-minute load during On-Peak hours in the billing period adjusted upward by 1% for each 1% that the power factor of Customer is below 95% lagging or leading.

Off-Peak: either A or B, whichever is greater.

A. The greatest 15-minute load during Off-Peak hours in the billing period adjusted upward by 1% for each 1% that the power factor of Customer is below 95% lagging or leading, minus the
On-Peak Billing Demand. Such demand will not be less than zero.

B. 68% of the Maximum Demand during the last 12 billing periods, minus the On-Peak Billing Demand. Such demand will not be less than zero. Part B of Off-Peak Billing Demand is not applicable to Industrial Service – Transmission Voltage (ETX).

Energy-Wise Plus Time-of-Day Peak Option (EIS-P, E8T-P, E8S-P, ELG-P, ECD-P)

Demand:

The greatest 15-minute load during any time in the billing period adjusted upward by 1% for each 1% that the power factor of Customer is below 95% lagging or leading.

Industrial Service – Large Load (ELL) see Sheet No. 27.1

ELECTRIC RATE SCHEDULES

GENERAL

TRANSMISSION AND PRIMARY SERVICE DEMAND CHARGE CREDIT

Transmission Service Demand Charge Credit

A Transmission Service Demand Charge Credit of $0.2738 per kW, per day will be applied to the Demand Charge Secondary for Customers receiving electric transmission service under the Industrial Service – Large Load (ELL) Rate Schedule. The credit is not applicable to all other kW, per day charges.

Primary Service Demand Charge Credit

A Primary Service Demand Charge Credit of $0.0118 per kW, per day will be applied to all applicable Demand Charges for Customers receiving electric primary service.

RATE OPTIONS

Residential and Commercial Service – Small (ETR-F, ETR-~~C~~P, ECS-F, ECS-P)

Rate options will be for a minimum twelve (12) consecutive billing periods.

All Other Rate Schedules

Customers may elect a rate option as more fully set forth on subsequent Electric Rate Schedules subject to any applicable separate eligibility and contract requirements as noted. Unless otherwise noted, the initial contract period is from the rate option service start date to December 31st. Unless otherwise stated and as long as the Customer continues to meet the eligibility requirements, the rate option service contract shall be automatically renewed for an additional 12-month contract period each January 1st unless Customer provides advance written notice to Utilities not less than 30 days prior to the January 1st renewal date that Customer elects not to renew for the upcoming rate option contract year. Customers will be evaluated periodically to ensure they continue to meet the specified rate option eligibility requirements. In the event that a Customer is no longer eligible, the contract for rate option service shall not be renewed and shall automatically terminate at the end of the 12-month contract period on December 31st. Upon termination, Customer shall be required to move to the rate schedule to which they are eligible upon the end of the contract period.

TIME-OF-DAY PERIODS

On-Peak Periods are Monday through Friday excluding the holidays as defined below. Unless otherwise provided On-Peak periods are as follows:

On-Peak Periods (excluding ETC, ETL)

January through December: 5:00 p.m. to 9:00 p.m.

Frozen Time-of-Day Service On-Peak Periods (ETC, ETL)

Winter (October through March): 4:00 p.m. to 10:00 p.m.
Summer (April through September): 11:00 a.m. to 6:00 p.m.

ELECTRIC RATE SCHEDULES

COMMERCIAL SERVICE – SMALL (ECS, ECS-P, ECS-F)

AVAILABILITY

As provided in the Energy-Wise, Energy-Wise Plus, and Fixed Seasonal Transition Terms and Conditions of these Electric Rate Schedules, service under this rate schedule is available in Utilities' electric service territory for any establishment engaged in the operation of a business or an institution, whether or not for profit, whose Maximum Demand is less than 10 kW in ~~any~~ each of the last 12 billing periods.

RATE OPTIONS

Customers may choose between the following:

A. Energy-Wise Standard Time-of-Day Option (ECS)
Service under this option is not available to Customers who receive service under the Renewable Energy Net Metering Rate Schedule.

B. Energy-Wise Plus Time-of-Day Option (ECS-P)
Service under this option is not available to Customers who: (a) receive service under the Renewable Energy Net Metering Rate Schedule; (b) receive service under the Community Solar Garden Bill Credit (Pilot Program) Rate Schedule, or (c) receive service under the Community Solar Garden Program Rate Schedule.

C. Fixed Seasonal Option (ECS-F)
Service under this option is not available to customers receiving service under the Renewable Energy Net Metering Rate Schedule.

RATE

See Rate Table for applicable charges.

ELECTRIC RATE SCHEDULES

INDUSTRIAL SERVICE – 4,000 kW MINIMUM (E8S, E8S-P)

AVAILABILITY

As provided in the Energy-Wise, Energy-Wise Plus, and Fixed Seasonal Transition Terms and Conditions of these Electric Rate Schedules, service under this rate schedule is available in Utilities' electric service territory for Customers whose Maximum Demand equals or exceeds 4,000 kW in any of the last 12 billing periods. Service is not available under this rate schedule for any Customer whose Maximum Demand equals or exceeds 10,000 kW in any of the last 12 billing periods or whose Maximum Demand is reasonably expected to equal or exceed 10,000 kW in any billing period in the next 120 billing periods.

RATE OPTIONS

Customers may choose between the following:

A. Energy-Wise Standard Time-of-Day Option (E8S)

B. Energy-Wise Plus Time-of-Day Option (E8S-P)
Service under this option is not available to Customers who: (a) receive service under the Renewable Energy Net Metering Rate Schedule; (b) receive service under the Community Solar Garden Bill Credit (Pilot Program) Rate Schedule, or (c) receive service under the Community Solar Garden Program Rate Schedule.

RATE

See Rate Table for applicable charges.

ELECTRIC RATE SCHEDULES

INDUSTRIAL SERVICE – LARGE POWER AND LIGHT (ELG, ELG-P)

AVAILABILITY

Available by contract in Utilities' electric service territory for the Customers whose aggregated Maximum Demand equals or exceeds 4,000 kW in any of the last 12 billing periods. Service is not available under this rate schedule for any Customer whose Maximum Demand equals or exceeds 10,000 kW in any of the last 12 billing periods or whose Maximum Demand is reasonably expected to equal or exceed 10,000 kW in any billing period in the next 120 billing periods. Demand aggregation may only be performed for contiguous service properties on a Customer campus setting. Customers must maintain an annual load factor of 75% or greater.

Annual load factor is derived by multiplying the annual kWh in the period by 100 and dividing by the product of the maximum real demand (prior to power factor correction) in kW and the number of hours in the period. Annual reviews will be conducted by Utilities at the end of the Customer's annual contract period. Annual kWh will be adjusted for Customers receiving service under the Interruptible Service Rate Schedule.

Customers who select this service will be required to provide a suitable location for the aggregation equipment. Totalization charges do not apply to this offering.

RATE OPTIONS

Customers may choose between the following:

A. Energy-Wise Standard Option (ELG)

B. Energy-Wise Plus Time-of-Day Option (ELG-P)
Service under this option is not available to Customers who: (a) receive service under the Renewable Energy Net Metering Rate Schedule; (b) receive service under the Community Solar Garden Bill Credit (Pilot Program) Rate Schedule, or (c) receive service under the Community Solar Garden Program Rate Schedule.

RATE

See Rate Table for applicable charges.

ELECTRIC RATE SCHEDULES

FROZEN INDUSTRIAL SERVICE – TIME-OF-DAY TRANSMISSION VOLTAGE (ETX)

AVAILABILITY

Available in Utilities' electric service territory for any Customer who has provided, installed, and maintains transformer(s) to receive three-phase, 60-hertz, alternating current electrical service at a nominal potential of 115,000 or 230,000 volts on the Customer's Premise. The Customer may be required to execute a contract with additional terms and conditions should service to the Customer under this rate schedule require any material change to Utilities' plant in service or operations. Unless Utilities determines temporarily establishing service under this rate schedule is in the best interest of Utilities, service under this rate schedule is frozen to new participation.

The Customer will provide, install, and maintain necessary switches, cutouts, protection equipment and the necessary wiring on the primary and secondary sides of the transformer(s). All equipment required to receive service that is installed and maintained by the Customer will be subject to approval by Utilities prior to installation and inspection or testing thereafter.

RATE

See Rate Table for applicable charges.

ELECTRIC RATE SCHEDULES

COMMUNITY SOLAR GARDEN PROGRAM

AVAILABILITY

The Community Solar Garden Program (Program) is available under the terms and conditions of this rate schedule to all Customers taking service under Utilities' Electric Rate Schedules with the following exceptions: ~~(a) Fixed Seasonal Options (ETR-F, ECS-F), (b)~~ (a) Energy-Wise Plus Time-of-Day Peak Options (ETR-P, ECS-P, ECM-P, ECL-P, EIS-P, E8T-P, E8S-P, ELG-P, ECD-P), ~~(c)~~ (b) Commercial Service – Non-Metered (ENM), ~~(d)~~(c) Contract Service – Military Wheeling (ECW), ~~(e)~~ (d) Contract Service – Traffic Signals (E2T), ~~(f)~~(e) Contract Service – Street Lighting (E7SL), ~~(g)~~ (f) Electric Cost Adjustment (ECA), ~~(h)~~ (g) Electric Capacity Charge (ECC), ~~(i)~~ (h) Totalization Service, ~~(j)~~ (i) Enhanced Power Service, ~~(k)~~ (j) Renewable Energy Net Metering, ~~(l)~~ (k) Small Power Producers & Cogeneration Service, and ~~(m)~~(l) Community Solar Garden Bill Credit (Pilot Program). All Customers that participate under this rate schedule must hold evidence of ownership to, a subscription as evidence of beneficial use of, or an entitlement to the electric generating capacity of a Community Solar Garden Facility (Customer Solar Garden Interest). Customers may choose any Community Solar Garden Facility that conforms to this rate schedule.

The choice of a Community Solar Garden Facility and the purchase of a Customer Solar Garden Interest is solely the responsibility of the Customer and are undertaken at the Customer's risk. Utilities makes no representations or warranties concerning the Community Solar Garden Facility and its operation and maintenance and its financial viability or the continued usefulness of any Customer Solar Garden Interest.

COMMUNITY SOLAR GARDEN FACILITY

A Community Solar Garden Facility for purposes of this rate schedule is a photovoltaic electric generating installation having a nameplate rating of not less than 0.5 megawatts Alternating Current (MWAC) and not more than 2.0 MWAC in electric generating capacity and the owning entity that has executed an Interconnection Agreement with Utilities. If the Interconnection Agreement is extended, Utilities will retain the Renewable Energy Credits through the extension period at no additional cost. The physical location of any Community Solar Garden Facility under this rate schedule shall be within the electric service territory of Utilities and any electric power produced by the Community Solar Garden Facility shall be consumed within the electric service territory of Utilities. All costs of interconnection for the Community Solar Garden Facility shall be borne and paid by the legal owner of the Community Solar Garden Facility.

This Program will allow for up to 2.0 MWAC of electric generating capacity to be added to Utilities' portfolio of Distributed Generation resources.

Approval Date: ~~November 12, 2024~~October 28, 2025
Effective Date: ~~October 1, 2025~~January 1, 2026
Resolution No. ~~172-24~~

ELECTRIC RATE SCHEDULES

INDUSTRIAL SERVICE – LARGE LOAD (ELL)

AVAILABILITY

Available by contract in Utilities' electric service territory for any Customer whose Maximum Demand equals or exceeds 10,000 kW in any of the last 12 billing periods, or whose Maximum Demand is reasonably expected to equal or exceed 10,000 kW in any billing period in the next 120 billing periods. If aggregation of loads is permitted by Utilities pursuant to the terms provided in this rate schedule, the Maximum Demand used for the purpose of determining availability under this rate schedule will be based on the aggregated Maximum Demand. Customers with common owner(s) or parent companies operating within a contiguous site will have loads aggregated for determining the Maximum Demand for the purposes of determining availability under this rate schedule.

SERVICE CONSIDERATIONS

A. Customers must submit a completed signed Large Load Service Agreement (LLSA) and pay all applicable fees and charges in order to qualify for service under this rate schedule. The LLSA shall specify provisions of service including the following but not limited to: annual load and energy requirements, load characteristics, construction related terms, operating procedures, the date of service availability, and administrative terms and conditions. The initial term of the LLSA will be established in the agreement but not be less than 10 years. Customers meeting the collateral waiver requirements as provided in this Rate Schedule are deemed to have completed the initial LLSA term.

B. Upon Utilities joining a Regional Transmission Organization (RTO), service under this rate schedule will be contingent upon and subject to the RTO's tariff provisions, and the Customer will be responsible for any cost incurred related to studies, interconnection, and service of the Customer's load.

C. Availability and terms of service are subject to Utilities and any applicable RTO study results and requirements. Interim service may be contingent upon the Customer being subject to interruption or curtailment under any applicable Utilities and/or RTO tariffs.

D. If extension or modification of Utilities' transmission system is required to provide service, the Customer shall be responsible for the cost of required extensions or modifications as set forth in Utilities' Rules and Regulations.

E. Customers must provide, install, and maintain transformer(s) to receive three-phase, 60-hertz, alternating current electrical service at nominal potential of 115,000 or 230,000 volts on the Customer Premise. Alternatively, where Utilities determines serving Customers through Utilities' substation

ELECTRIC RATE SCHEDULES

INDUSTRIAL SERVICE – LARGE LOAD (ELL)

facilities is in the best interest, Customers shall pay the applicable Substation Facility Fees as set forth in Utilities' Rules and Regulations. Customers paying the Substation Facility Fees must provide, install, and maintain equipment to receive Primary or Secondary Service as provided in Utilities' Rules and Regulations and in accordance with the *Line Extension and Service Standards* for Electric.

F. Service will generally be provided through one meter unless Utilities, in its sole discretion, determines additional meters and aggregation is warranted. The aggregation terms and conditions set forth in the Industrial Service – Large Power and Light (ELG) Rate Schedule will apply.

G. If in Utilities determination, the Customers load cannot be served by Utilities existing capabilities, the Customer will be served on an interim basis through market agreement(s) for capacity and energy requirements for a period of time not to exceed the 10-year term of the initial LLSA. In lieu of ECA and ECC charges, Utilities will bill the Customer the full costs of the market agreement(s) through charges as set forth in the LLSA and these Electric Rate Schedules.

H. Except for Customers whose collateral requirements have been waived pursuant to the terms provided in this rate schedule below, Customers will be subject to the Resource Adequacy Charge and the System Support Charge, as set forth in these Electric Rate Schedules, for each billing period in the initial 10-year term of the LLSA.

I. If at any time the Customer's actual maximum demand exceeds the contracted annual load requirements, the Customer shall provide an updated annual load requirement and the LLSA shall be updated to reflect the higher demand.

J. Utilities has no obligation to serve loads in excess of the contracted demand for the calendar year as provided in the LLSA.

DEMAND AND ENERGY DETERMINATIONS

A. During the initial 10-year LLSA period, Billing Demand will be the highest of (1) the greatest 15-minute load in the billing period adjusted upward by 1% for each 1% that the power factor of Customer is below 95% lagging or leading, (2) 100% of the Maximum Demand occurring during the last 12 billing periods, or (3) 100% of the contracted demand for the calendar year as provided in the LLSA.

B. After the initial 10-year LLSA period, Billing Demand will be the highest of the greatest 15-minute load in the billing period adjusted upward by 1% for each 1% that the power factor of Customer is below 95% lagging or leading, or 68% of the Maximum Demand occurring during the last 12 billing periods.

C. During the initial 10-year LLSA period, Billing Energy will be the higher of metered energy for the billing period, or contracted monthly energy as set forth in market agreement and the LLSA.

D. After the initial 10-year LLSA period, Billing Energy will be equal to the metered energy for the billing period.

MINIMUM MONTHLY BILL

The Minimum Monthly Bill will be the sum of applicable Access and Facilities, Demand, Generation Capacity Charge, System Support Charge, market agreement charges, ECA, ECC, and all other applicable charges calculated using the Billing Demand, Billing Energy, and other applicable billing determinates as defined in these Electric Rate Schedules, Utilities' Rules and Regulations, and the LLSA.

COLLATERAL REQUIREMENT DETERMINATION

A. The collateral requirement under this rate schedule is in place of the Electric portion of deposits for starting service under Utilities' Rules and Regulations. Deposits relating to starting service for Natural Gas, Water, and Wastewater services provided by Utilities shall apply as provided in Utilities' Rules and Regulations and Utilities' Tariffs.

B. The collateral requirement is equal to the highest 36 months of estimated Minimum Monthly Bills occurring during the LLSA term. Estimation of the highest 36 monthly bills will be calculated using the demand and energy requirements as provided in the LLSA.

C. If during the LLSA term the annual load or energy requirements increase from those provided in the initial agreement, additional collateral will be required such that the total collateral requirement equals the highest 36 months of estimated bills for the service contract based on the updated annual load and energy requirements.

D. The Customer must provide the collateral requirement in one or more of the following forms:
   1. Cash for the full collateral requirement. Interest will not be accrued on cash collateral; or

   2. A standby irrevocable Letter of Credit (LOC) for the full collateral requirement. The LOC must be issued by a U.S. bank or the U.S. branch of a foreign bank, which is not affiliated with the

Customer, with a credit rating of at least A- from Standard & Poor's (S&P) and A3 from Moody's, as well as a minimum capitalization of at least $250 million. Such security must be issued for a minimum term of 360 days. The Customer must cause the renewal or extension of the security for additional consecutive terms of 360 days or more no later than 30 days prior to each expiration date of the security through the entire service contract term and provide Utilities written notice of such renewal. If the security is not renewed or extended as required herein, Utilities will have the right to draw immediately upon the LOC and be entitled to hold the amounts so drawn as security. The LOC must be in a format acceptable to and approved by Utilities.

E. Utilities may waive collateral requirements for Customers who have maintained service under an Industrial Service Rate Schedule for the preceding 120 billing periods, and each of the following conditions apply:

1. The Customer has not had any delinquency within the preceding 120 billing periods; and

2. The Customer's maximum rolling 12-month load to rolling 12-month average load ratio has not exceeded 1.20 in any month in the preceding 120 billing periods; and

3. The Customer's load is not expected to increase by more than 5 MW within the next 120 billing periods; and

4. In the event of merger, acquisition, or legal transfer of interest or other event causing a change in the Customer name and/or identification, the Customer demonstrates successorship in interest from the predecessor to the successor entity.

5. If circumstances related to Utilities' prior waiver of collateral requirements change and are no longer applicable, the collateral requirement will be immediately due.

TERMS AND CONDITIONS

A. During the term of the LLSA the Customer may terminate service by providing written notice to Utilities no less than 36 months prior to the requested service end date. The LLSA will automatically renew for an additional 36 months at the end of each LLSA term unless Customer provides advance written notice of termination no less than 36 months prior to expiration.

ELECTRIC RATE SCHEDULES

INDUSTRIAL SERVICE – LARGE LOAD (ELL)

B. Upon termination the Customer is responsible for paying a LLSA Termination Fee equal to the estimated Minimum Monthly Bills remaining in the LLSA term or the highest 36 months of estimated Minimum Monthly Bills occurring during the LLSA, whichever is greater.

C. 36 months prior to LLSA renewal, Utilities or the Customer may request modification of the load and energy requirement.

RATE

See Rate Table for applicable charges.

PAYMENT

Payment of billing statements is due and payable by the date indicated in the billing statement. If full payment of charges is not made on or prior to the due date, a late payment fee of 1.5% per month will be assessed on the overdue balance. Collateral requirements will be called when Utilities initiates Discontinuance of Service by Utilities for Failure to Pay When Due as provided in Utilities Rules and Regulations.

Electric

Redline Tariff Sheets

Effective April 1, 2026

ELECTRIC RATE SCHEDULES

RATE TABLE

Description	Rates (Note)				
	2025	2026	2027	2028	2029
Summer (June – September), per kW, per day	$0.0366	$0.0390	$0.0415	$0.0442	$0.0471
Access and Facilities Charge:					
Winter (October – May) On-Peak, per kWh	$0.0407	$0.0433	$0.0461	$0.0491	$0.0523
Winter (October – May) Off-Peak, per kWh	$0.0276	$0.0294	$0.0313	$0.0333	$0.0355
Winter (October – May) Off-Peak Saver, per kWh	$0.0114	$0.0121	$0.0129	$0.0137	$0.0146
Summer (June – September) On-Peak, per kWh	$0.1293	$0.1377	$0.1467	$0.1562	$0.1664
Summer (June – September) Off-Peak, per kWh	$0.0276	$0.0294	$0.0313	$0.0333	$0.0355
Summer (June – September) Off-Peak Saver, per kWh	$0.0142	$0.0151	$0.0161	$0.0171	$0.0182
Critical Peak Period (During Event Hours), per kWh	$0.4578	$0.4876	$0.5193	$0.5531	$0.5891
Electric Cost Adjustment (ECA):					
On-Peak, per kWh	Sheet No. 2.17				
Off-Peak, per kWh	Sheet No. 2.17				
Off-Peak Saver, per kWh	Sheet No. 2.17				
Electric Capacity Charge (ECC), per kWh	Sheet No. 2.18				
Optional Service (EHYDPWR, EINFPRS)					
See rate and charge detail in tariff					
Contract Service – Military Wheeling (ECW) – Sheet No. 13					
Required Services					
Wheeling Demand Charge, per kW, per day	$0.0806	~~$0.0858~~ $0.2009	~~$0.0914~~ $0.2140	~~$0.0973~~ $0.2279	~~$0.1036~~ $0.2427
~~Open Access Transmission Service (see Open Access Transmission Tariff for applicable charges)~~					
Contract Service – Traffic Signals (E2T) – Sheet No. 14					
Access and Facilities Charge, per day	$0.5135	$0.5613	$0.6135	$0.6706	$0.7330
Access and Facilities Charge, per kWh	$0.0949	$0.1037	$0.1133	$0.1238	$0.1353
Electric Cost Adjustment (ECA), per kWh	Sheet No. 2.17				
Electric Capacity Charge (ECC), per kWh	Sheet No. 2.18				

Approval Date: ~~November 12, 2024~~ October 28, 2025
Effective Date: ~~October 1, 2025~~ April 1, 2026
Resolution No. ~~172-24~~

Note: 2025 rates are effective October 1, 2025. 2026 ECW rate is effective starting April 1, 2026. All other rates are effective January 1st of the respective year shown. Rates effective 2029 will remain effective until superseded by City Council.

ELECTRIC RATE SCHEDULES

CONTRACT SERVICE – MILITARY WHEELING (ECW)

AVAILABILITY

Available by contract in Utilities' electric service territory to the United States of America at the Peterson Space Force Base, the Cheyenne Mountain Space Force Station, the United States Air Force Academy and the Fort Carson Military Installation. Service under this rate schedule is not available to any other Customer or entity.

Service is offered at the request of Customer so that Customer may purchase an allocated portion of its power and energy requirements from the Western Area Power Administration (Western). Service is also offered at the request of Customer to allow the Fort Carson Military Installation (Fort Carson) to purchase a portion of its power and energy requirements from Utilities under Contract Service – Military (EHYDPWR) (Hydro Power tariff). These Customer purchases from Western or from Utilities will be under a long-term contract for firm capacity and associated energy. Utilities will wheel (transport), subject to available capacity, such energy over Utilities' transmission and distribution systems to Customer's facility. Electric requirements of the Customer in excess of its allocation from Western or in excess of its purchases under the Hydro Power tariff will be supplied by Utilities as supplemental power and energy.

APPLICABILITY

Service under this rate schedule will be provided only if a contract for such service is in effect between Customer and Utilities. Services other than distribution wheeling provided to Customer by Utilities are limited to services set forth within this rate schedule and separately contracted for by Customer. Services provided by Utilities under this rate schedule are strictly limited to power and energy requirements of each Customer within its boundaries. Under no circumstances will Customer resell any power and/or energy provided under this rate schedule, or use in any way such power or energy outside the confines of Customer's facility.

REQUIRED SERVICES

Customer must contract for the following services:

A. Wheeling

B. Supplemental Power and Energy

C. ~~Open Access Transmission Service (See Open Access Transmission Tariff)~~

ELECTRIC RATE SCHEDULES

CONTRACT SERVICE – MILITARY WHEELING (ECW)

Wheeling

Wheeling is defined as the transporting of power and energy over Utilities' transmission and distribution system for redelivery of Customer's allocated portion of its power and energy from Western or for Customer's purchase of power and energy from Utilities under the Hydro Power tariff. This rate schedule ~~only~~ pertains to wheeling over Utilities' transmission and distribution system. ~~Wheeling service over Utilities' transmission system must be arranged under the Open Access Transmission Tariff.~~ Customer must furnish to Utilities copies of contracts and/or agreements between Customer and Western, and between Customer and any intermediate wheeling source. Utilities will maintain copies of Customer's purchases under the Hydro Power tariff. Wheeling availability is always subject to capacity constraints of Utilities' transmission and distribution system and any intermediate wheeling parties' transmission limitations. When Utilities identifies a transmission capacity constraint, Utilities agrees to provide notice to the Customer and to work with the Customer in developing an alternative transmission arrangement.

This service is contingent upon the availability of a transmission and distribution wheeling path from the point of interconnection to Customer's facility. Wheeling will be provided if and when capacity is available above the needs of Utilities' firm Customers.

This service is available to Customer for power and energy purchased from Western and delivered to Utilities' points of interconnection pursuant to a contract between Customer and Utilities. This service is also available to Customer for power and energy purchases from Utilities under the Hydro Power tariff and delivered to Customer. Absent physical or safety constraints, Utilities will redeliver all of Customer's power and energy scheduled and delivered from Western (or purchased by Customer from Utilities under the Hydro Power tariff) to Utilities' points of interconnection with Customer. Utilities shall not be liable for failing to deliver power to Customer either because of interruption of scheduled deliveries from Western (or interruption of deliveries under the Hydro Power tariff) or malfunctions within Utilities' transmission and distribution system or interruptions of wheeling service by intermediate wheeling parties.

Electric

Redline Tariff Sheets

Effective January 1, 2027

ELECTRIC RATE SCHEDULES

TABLE OF CONTENTS

DESCRIPTION **SHEET NO.**

ELECTRIC RATE SCHEDULES

RATE TABLE

Description	Rates (Note)				
	2025	2026	2027	2028	2029
Summer (June – September) Off-Peak, per kWh	$0.0730	$0.0777	$0.0827	$0.0880	$0.0936
Summer (June – September) Off-Peak Saver, per kWh	$0.0517	$0.0550	$0.0585	$0.0622	$0.0662
Critical Peak Period (During Event Hours), per kWh	$0.6613	$0.7036	$0.7486	$0.7965	$0.8475
Electric Cost Adjustment (ECA):					
On-Peak, per kWh	Sheet No. 2.17				
Off-Peak, per kWh	Sheet No. 2.17				
Off-Peak Saver, per kWh	Sheet No. 2.17				
Electric Capacity Charge (ECC), per kWh	Sheet No. 2.18				
Fixed Seasonal Option (ETR-F)					
Access and Facilities Charge, per day	$0.7316	$0.7784	$0.8282	$0.8812	$0.9376
Access and Facilities Charge:					
Winter (October – May), per kWh	$0.0763	$0.0812	$0.0864	$0.0919	$0.0978
Summer (June – September), per kWh	$0.1007	$0.1071	$0.1140	$0.1213	$0.1291
Electric Cost Adjustment (ECA), per kWh	Sheet No. 2.17				
Electric Capacity Charge (ECC), per kWh	Sheet No. 2.18				
Energy-Wise Net Metering Option (ERNM)	Sheet No. 2.20				
Frozen Commercial Service – Small (E1C) – Sheet No. 5					
Access and Facilities Charge, per day	$0.6421	$0.6832	$0.7269	$0.7734	$0.8229
Access and Facilities Charge, per kWh	$0.0876	$0.0932	$0.0992	$0.1055	$0.1123
Electric Cost Adjustment (ECA), per kWh	Sheet No. 2.17				
Electric Capacity Charge (ECC), per kWh	Sheet No. 2.18				
Commercial Service – Non-Metered (ENM) – Sheet No. 5.1					
Access and Facilities Charge, per kWh	$0.1172	$0.1295	$0.1431	$0.1581	$0.1747
Electric Cost Adjustment (ECA), per kWh	Sheet No. 2.17				
Electric Capacity Charge (ECC), per kWh	Sheet No. 2.18				

Approval Date: ~~November 12, 2024~~October 28, 2025
Effective Date: ~~October 1, 2025~~January 1, 2027
Resolution No. ~~172-24~~

Note: 2025 rates are effective October 1, 2025. All other rates are effective January 1st of the respective year shown. Rates effective 2029 will remain effective until superseded by City Council.

ELECTRIC RATE SCHEDULES

RATE TABLE

Description	Rates (Note)				
	2025	2026	2027	2028	2029
Off-Peak Saver, per kWh	Sheet No. 2.17				
Electric Capacity Charge (ECC), per kWh	Sheet No. 2.18				
Fixed Seasonal Option (ECS-F)					
Access and Facilities Charge, per day	$0.7549	$0.8032	$0.8546	$0.9093	$0.9675
Access and Facilities Charge:					
Winter (October – May), per kWh	$0.0739	$0.0786	$0.0836	$0.0890	$0.0947
Summer (June – September), per kWh	$0.0782	$0.0832	$0.0885	$0.0942	$0.1002
Electric Cost Adjustment (ECA):	Sheet No. 2.17				
Electric Capacity Charge (ECC), per kWh	Sheet No. 2.18				
Energy-Wise Net Metering Option (ECSNM)	Sheet No. 2.20				
Frozen Commercial Service – General (E2C, ETC) – Sheet No. 6					
Frozen Standard Option (E2C)					
Access and Facilities Charge, per day	$1.0500	$1.1130	$1.1798	$1.2506	$1.3256
Access and Facilities Charge, per kWh	$0.0748	$0.0793	$0.0840	$0.0891	$0.0944
Electric Cost Adjustment (ECA):	Sheet No. 2.17				
Electric Capacity Charge (ECC), per kWh	Sheet No. 2.18				
Frozen Time-of-Day Option (ETC)					
Access and Facilities Charge, per day	$1.0500	$1.1130	$1.1798	$1.2506	$1.3256
Access and Facilities Charge:					
On-Peak, per kWh	$0.1384	$0.1467	$0.1555	$0.1648	$0.1747
Off-Peak, per kWh	$0.0554	$0.0587	$0.0622	$0.0660	$0.0699
Electric Cost Adjustment (ECA):					
On-Peak, per kWh	Sheet No. 2.17				
Off-Peak, per kWh	Sheet No. 2.17				
Electric Capacity Charge (ECC), per kWh	Sheet No. 2.18				

Note: 2025 rates are effective October 1, 2025. All other rates are effective January 1st of the respective year shown. Rates effective 2029 will remain effective until superseded by City Council.

ELECTRIC RATE SCHEDULES

RATE TABLE

Description	Rates (Note)				
	2025	2026	2027	2028	2029
Summer (June – September) Off-Peak, per kWh	$0.0497	$0.0527	$0.0559	$0.0593	$0.0629
Summer (June – September) Off-Peak Saver, per kWh	$0.0363	$0.0385	$0.0408	$0.0432	$0.0458
Critical Peak Period (During Event Hours), per kWh	$0.6781	$0.7188	$0.7619	$0.8076	$0.8561
Electric Cost Adjustment (ECA):					
On-Peak, per kWh	Sheet No. 2.17				
Off-Peak, per kWh	Sheet No. 2.17				
Off-Peak Saver, per kWh	Sheet No. 2.17				
Electric Capacity Charge (ECC), per kWh	Sheet No. 2.18				
Energy-Wise Net Metering Option (ECMNM)	Sheet No. 2.20				
Commercial Service – Large 50 kW Minimum (ECL, ECL-P)– Sheet No. 6.2					
Energy-Wise Standard Time-of-Day Option (ECL)					
Access and Facilities Charge, per day	$1.4598	$1.5474	$1.6402	$1.7386	$1.8429
Demand Charge Secondary:					
Winter (October – May), per kW, per day	$0.0172	$0.0182	$0.0193	$0.0205	$0.0217
Summer (June – September), per kW, per day	$0.0480	$0.0509	$0.0540	$0.0572	$0.0606
Access and Facilities Charge:					
Winter (October – May) On-Peak, per kWh	$0.0839	$0.0889	$0.0942	$0.0999	$0.1059
Winter (October – May) Off-Peak, per kWh	$0.0595	$0.0631	$0.0669	$0.0709	$0.0752
Summer (June – September) On-Peak, per kWh	$0.0993	$0.1053	$0.1116	$0.1183	$0.1254
Summer (June – September) Off-Peak, per kWh	$0.0595	$0.0631	$0.0669	$0.0709	$0.0752
Electric Cost Adjustment (ECA):					
On-Peak, per kWh	Sheet No. 2.17				
Off-Peak, per kWh	Sheet No. 2.17				
Electric Capacity Charge (ECC), per kWh	Sheet No. 2.18				
Energy-Wise Plus Time-of-Day Option (ECL-P)					
Access and Facilities Charge, per day	$1.4598	$1.5474	$1.6402	$1.7386	$1.8429

Note: 2025 rates are effective October 1, 2025. All other rates are effective January 1st of the respective year shown. Rates effective 2029 will remain effective until superseded by City Council.

ELECTRIC RATE SCHEDULES

RATE TABLE

Description	Rates (Note)				
	2025	2026	2027	2028	2029
Demand Charge Secondary:					
Winter (October – May), per kW, per day	$0.0756	$0.0801	$0.0849	$0.0900	$0.0954
Summer (June – September), per kW, per day	$0.0937	$0.0993	$0.1053	$0.1116	$0.1183
Access and Facilities Charge:					
Winter (October – May) On-Peak, per kWh	$0.0564	$0.0598	$0.0634	$0.0672	$0.0712
Winter (October – May) Off-Peak, per kWh	$0.0443	$0.0470	$0.0498	$0.0528	$0.0560
Winter (October – May) Off-Peak Saver, per kWh	$0.0266	$0.0282	$0.0299	$0.0317	$0.0336
Summer (June – September) On-Peak, per kWh	$0.1707	$0.1809	$0.1918	$0.2033	$0.2155
Summer (June – September) Off-Peak, per kWh	$0.0443	$0.0470	$0.0498	$0.0528	$0.0560
Summer (June – September) Off-Peak Saver, per kWh	$0.0306	$0.0324	$0.0343	$0.0364	$0.0386
Critical Peak Period (During Event Hours), per kWh	$0.5878	$0.6231	$0.6605	$0.7001	$0.7421
Electric Cost Adjustment (ECA):					
On-Peak, per kWh	Sheet No. 2.17				
Off-Peak, per kWh	Sheet No. 2.17				
Off-Peak Saver, per kWh	Sheet No. 2.17				
Electric Capacity Charge (ECC), per kWh	Sheet No. 2.18				
Energy-Wise Net Metering Option (ECLNM)	Sheet No. 2.20				
Frozen Industrial Service – 1,000 kWh/Day Minimum (ETL, ETLO, ETLW) – Sheet No. 7					
Frozen Standard Option (ETL)					
Access and Facilities Charge, per day	$3.5132	$3.7187	$3.9363	$4.1665	$4.4103
Demand Charge Secondary:					
On-Peak, per kW, per day	$0.8459	$0.8954	$0.9478	$1.0032	$1.0619
Off-Peak, per kW, per day	$0.5498	$0.5820	$0.6160	$0.6520	$0.6902
Electric Cost Adjustment (ECA):					
On-Peak, per kWh	Sheet No. 2.17				
Off-Peak, per kWh	Sheet No. 2.17				

Note: 2025 rates are effective October 1, 2025. All other rates are effective January 1st of the respective year shown. Rates effective 2029 will remain effective until superseded by City Council.

ELECTRIC RATE SCHEDULES

RATE TABLE

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Note: All rates are effective January 1st of the respective year shown. Rates effective 2029 will remain effective until superseded by City Council.

ELECTRIC RATE SCHEDULES

RATE TABLE

Description	**Rates (Note)**		
	2027	**2028**	**2029**
Net Metering – Sheet No. 20			
Residential Service Energy-Wise Net Metering Option (ERNM) – Sheet No. 4			
Access and Facilities Charge, per day	$0.8265	$0.8802	$0.9374
Access and Facilities Charge, per kWh	$0.0294	$0.0313	$0.0333
Demand Charge Secondary, per kW, per day	$0.4329	$0.4610	$0.4910
Electric Cost Adjustment (ECA), per kWh		$0.0263	
Electric Capacity Charge (ECC), per kWh		$0.0066	
Commercial Service – Small Energy-Wise Net Metering Option (ECSNM) – Sheet No. 5.2			
Access and Facilities Charge, per day	$0.8265	$0.8802	$0.9374
Access and Facilities Charge, per kWh	$0.0294	$0.0313	$0.0333
Demand Charge Secondary, per kW, per day	$0.3456	$0.3681	$0.3920
Electric Cost Adjustment (ECA), per kWh		$0.0263	
Electric Capacity Charge (ECC), per kWh		$0.0066	
Commercial Service – Medium Energy-Wise Net Metering Option (ECMNM) – Sheet No. 6.1			
Access and Facilities Charge, per day	$1.1759	$1.2523	$1.3337
Access and Facilities Charge, per kWh	$0.0505	$0.0538	$0.0573
Demand Charge Secondary, per kW, per day	$0.4662	$0.4965	$0.5288
Electric Cost Adjustment (ECA), per kWh		$0.0263	
Electric Capacity Charge (ECC), per kWh		$0.0056	
Commercial Service – Large Energy-Wise Net Metering Option (ECLNM) – Sheet No. 6.2			
Access and Facilities Charge, per day	$1.5253	$1.6244	$1.7300
Access and Facilities Charge, per kWh	$0.0470	$0.0501	$0.0534
Demand Charge Secondary, per kW, per day	$0.4662	$0.4965	$0.5288
Electric Cost Adjustment (ECA), per kWh		$0.0263	
Electric Capacity Charge (ECC), per kWh		$0.0056	
All Other Rate Schedules billed under applicable Energy-Wise standard or frozen option.			

Note: All rates are effective January 1st of the respective year shown. Rates effective 2029 will remain effective until superseded by City Council.

ELECTRIC RATE SCHEDULES

GENERAL

DEMAND DETERMINATIONS

Commercial Service (ECM, ECM-P, ECL, ECL-P)

Maximum Demand and/or Billing Demand:

Greatest 15-minute load during any block of time in the billing period.

Residential and Commercial Energy-Wise Net Metering (ERNM, ECSNM, ECMNM, ECLNM):

Greatest 15-minute net load during any On-Peak Period in the billing period.

Industrial and Contract Service

Maximum Demand (ETL, EIS, EIS-P, E8T, E8T-P, E8S, E8S-P, ELG, ELG-P, ETX, ECD, ECD-P, ELL)

Maximum Demand is the greatest 15-minute load during any time in the billing period adjusted upward by 1% for each 1% that the power factor of Customer is below 95% lagging or leading.

Billing Demand

Energy-Wise Standard Time-of-Day Option (ETL, EIS, E8T, E8S, ELG, ETX, ECD)

On-Peak:

The greatest 15-minute load during On-Peak hours in the billing period adjusted upward by 1% for each 1% that the power factor of Customer is below 95% lagging or leading.

Off-Peak: either A or B, whichever is greater.

A. The greatest 15-minute load during Off-Peak hours in the billing period adjusted upward by 1% for each 1% that the power factor of Customer is below 95% lagging or leading, minus the
On-Peak Billing Demand. Such demand will not be less than zero.

B. 68% of the Maximum Demand during the last 12 billing periods, minus the On-Peak Billing Demand. Such demand will not be less than zero. Part B of Off-Peak Billing Demand is not applicable to Industrial Service – Transmission Voltage (ETX).

Energy-Wise Plus Time-of-Day Peak Option (EIS-P, E8T-P, E8S-P, ELG-P, ECD-P)

Demand:

The greatest 15-minute load during any time in the billing period adjusted upward by 1% for each 1% that the power factor of Customer is below 95% lagging or leading.

Industrial Service – Large Load (ELL) see Sheet No. 27.1

ELECTRIC RATE SCHEDULES

GENERAL

ENERGY-WISE, ENERGY-WISE PLUS, AND FIXED SEASONAL TRANSITION TERMS AND CONDITIONS

Residential Service

Unless Utilities, at its sole discretion, determines temporarily establishing service under the Frozen Option (E1R) is in best interest of Utilities, Customers establishing service after September 30, 2025, will initially receive service under the Energy-Wise Standard Time-of-Day Option (ETR) unless request is made to receive service under the alternate Energy-Wise Plus Time-of-Day (ETR-P) or the Fixed Seasonal (ETR-F) options. With the exception for Customers receiving service under the ~~Renewable Energy~~ Net Metering Rate Schedule (which are addressed below), Customers with standard meters receiving service under the Frozen Option (E1R) will be transitioned to service under the Energy-Wise Standard Time-of-Day Option (ETR) according to a schedule determined by Utilities. If eligible, Customers with standard meters receiving service under the Frozen Option (E1R) may request to receive service under the Energy-Wise Standard Time-of-Day (ETR), the Energy-Wise Plus Time-of-Day Option (ETR-P), or the Fixed Seasonal Option (ETR-F). However, Utilities, at its sole discretion, may decline such requests based on Utilities' transition schedule or other operational considerations. Customers receiving service under the Frozen Option (E1R) who have chosen to receive a nonstandard meter under Utilities' Automated-Meter Opt-Out Program will be transitioned to the Fixed Seasonal Option (ETR-F). Customers receiving service under the Net Metering Rate Schedule will be transitioned to service under the Energy-Wise Net Metering Option (ERNM) on January 1, 2027.

Commercial and Industrial Service

Service under Frozen Rate Schedules (E1C, E2C, ETC, ETL, ETLO, ETLW) is frozen to new participation, except in instances when Customers on frozen rate schedules are switched to the appropriate frozen rate schedule under Utilities' Dynamic Rate Switching. Unless Utilities, at its sole discretion, determines temporarily establishing service under Frozen Rate Schedules (E1C, E2C, ETL) is in the best interest of Utilities, Customers establishing service after September 30, 2025, will initially receive service under the appropriate Commercial Service – Small (ECS, ECS-P, ECS-F), Commercial Service – Medium 10 kW Minimum (ECM, ECM-P), Commercial Service – Large 50 kW Minimum (ECL, ECL-P), Industrial Service – 100 kW Minimum (EIS, EIS-P), Industrial Service – 500 kW Minimum (E8T, E8T-P), or Industrial Service – 4,000 kW Minimum (E8S, E8S-P) Rate Schedule. With the exception of customers receiving service under the ~~Renewable Energy~~ Net Metering Rate Schedule, Customers receiving service under Frozen Rate Schedules (E1C, E2C, ETC, ETL, ETLO, ETLW) will be transitioned to the applicable Commercial Service – Small (ECS), ~~Commercial Service – Medium 10 kW Minimum (ECM), Commercial Service – Large 50 kW~~

ELECTRIC RATE SCHEDULES

GENERAL

~~Minimum (ECL), Industrial Service – 100 kW Minimum (EIS), Industrial Service – 500 kW Minimum (E8T), or Industrial Service – 4,000 kW Minimum (E8S) Energy-Wise Standard~~

Commercial Service – Medium 10 kW Minimum (ECM), Commercial Service – Large 50 kW Minimum (ECL), Industrial Service – 100 kW Minimum (EIS), Industrial Service – 500 kW Minimum (E8T), or Industrial Service – 4,000 kW Minimum (E8S) Energy-Wise Standard Time-of-Day Option according to a schedule determined by Utilities. If eligible, Customers receiving service under Frozen Rate Schedules (E1C, E2C, ETC, ETL, ETLO, ETLW) may request to receive service under the applicable Commercial Service – Small (ECS, ECS-P, ECS-F), Commercial Service – Medium 10 kW Minimum (ECM, ECM-P), Commercial Service – Large 50 kW Minimum (ECL, ECL-P), Industrial Service – 100 kW Minimum (EIS, EIS-P), Industrial Service – 500 kW Minimum (E8T, E8T-P), or Industrial Service – 4,000 kW Minimum (E8S, E8S-P) Rate Schedule. However, Utilities at its sole discretion may decline such requests based on Utilities' transition schedule or other operational considerations.

Customers receiving service under Commercial Service – Small (ECS, ECS-P), Commercial Service – Medium 10 kW Minimum (ECM, ECM-P), Commercial Service – Large 50 kW Minimum (ECL, ECL-P), Industrial Service – 100 kW Minimum (EIS, EIS-P), Industrial Service – 500 kW Minimum (E8T, E8T-P), or Industrial Service – 4,000 kW Minimum (E8S, E8S-P) Rate Schedule will be switched to the appropriate rate schedule under Utilities' Dynamic Rate Switching. ~~Customers receiving service under the Renewable Energy Net Metering Rate Schedule will continue to receive service under the applicable frozen schedules, under Utilities Dynamic Rate Switching, until otherwise provided by Utilities~~Commercial Customers receiving service under the Net Metering Rate Schedule will be transitioned to service under the applicable Energy-Wise Net Metering Option (ECSNM, ECMNM, ECLNM) on January 1, 2027.

ELECTRIC RATE SCHEDULES

RESIDENTIAL SERVICE (E1R, ETR, ETR-P, ETR-F, ERNM)

AVAILABILITY

As provided in the Energy-Wise, Energy-Wise Plus, and Fixed Seasonal Transition Terms and Conditions of these Electric Rate Schedules, service under this rate schedule is available in Utilities' electric service territory for general residential purposes. Whether or not the end use of the electric service is residential in nature, this rate is not available for master metered or nonresidential accounts.

RATE OPTIONS

Customers may choose between the following:

A. Frozen Option (E1R)
~~With the exception for Customers receiving service under the Renewable Energy Net Metering Rate Schedule, u~~Unless Utilities determines temporarily establishing service under this option is in the best interest of Utilities, service under this option is frozen to new participation.

B. Energy-Wise Standard Time-of-Day Option (ETR)
Service under this option is not available to Customers choosing to receive a nonstandard meter under Utilities' Automated-Meter Opt-Out Program. Service under this option is not available to customers receiving service under the ~~Renewable Energy~~ Net Metering Rate Schedule.

C. Energy-Wise Plus Time-of-Day Option (ETR-P)
Service under this option is not available to Customers who: (a) choose to receive a nonstandard meter under Utilities Automated-Meter Opt-Out Program; b) receive service under the ~~Renewable Energy~~ Net Metering Rate Schedule; c) receive service under the Community Solar Garden Bill Credit (Pilot Program) or Community Solar Garden Program Rate Schedules.

D. Fixed Seasonal Option (ETR-F)
Customers choosing to receive a nonstandard meter under Utilities' Automated-Meter Opt-Out Program are required to receive service under this option. Service under this option is not available to customers receiving service under the ~~Renewable Energy~~ Net Metering Rate Schedule.

E. Energy-Wise Net Metering Option (ERNM)
Service under this option is available to customers receiving service under the Net Metering Rate Schedule.

RATE

See Rate Table for applicable charges.

ELECTRIC RATE SCHEDULES

FROZEN COMMERCIAL SERVICE – SMALL (E1C)

AVAILABILITY

As provided in the Energy-Wise, Energy-Wise Plus, and Fixed Seasonal Transition Terms and Conditions of these Electric Rate Schedules, service under this rate schedule is available in Utilities' electric service territory for any establishment engaged in the operation of a business or an institution, whether or not for profit, whose average daily usage (billing period kWh divided by the number of days in the billing period) does not exceed 33 kWh in any of the last 12 billing periods. ~~With the exception for Customers receiving service under the Renewable Energy Net Metering Rate Schedule, unless~~ Unless Utilities determines temporarily establishing service under this option is in the best interest of Utilities, service under this option is frozen to new participation.

RATE

See Rate Table for applicable charges.

ELECTRIC RATE SCHEDULES

COMMERCIAL SERVICE – SMALL (ECS, ECS-P, ECS-F, ECSNM)

AVAILABILITY

As provided in the Energy-Wise, Energy-Wise Plus, and Fixed Seasonal Transition Terms and Conditions of these Electric Rate Schedules, service under this rate schedule is available in Utilities' electric service territory for any establishment engaged in the operation of a business or an institution, whether or not for profit, whose Maximum Demand is less than 10 kW in each of the last 12 billing periods.

RATE OPTIONS

Customers may choose between the following:

A. Energy-Wise Standard Time-of-Day Option (ECS)
Service under this option is not available to Customers who receive service under the ~~Renewable Energy~~ Net Metering Rate Schedule.

B. Energy-Wise Plus Time-of-Day Option (ECS-P)
Service under this option is not available to Customers who: (a) receive service under the ~~Renewable Energy~~ Net Metering Rate Schedule; (b) receive service under the Community Solar Garden Bill Credit (Pilot Program) Rate Schedule, or (c) receive service under the Community Solar Garden Program Rate Schedule.

C. Fixed Seasonal Option (ECS-F)
Service under this option is not available to customers receiving service under the ~~Renewable Energy~~ Net Metering Rate Schedule.

D. Energy-Wise Net Metering Option (ECSNM)
Service under this option is available to customers receiving service under the Net Metering Rate Schedule.

RATE

See Rate Table for applicable charges.

ELECTRIC RATE SCHEDULES

FROZEN COMMERCIAL SERVICE – GENERAL (E2C, ETC)

AVAILABILITY

As provided in the Energy-Wise, Energy-Wise Plus, and Fixed Seasonal Transition Terms and Conditions of these Electric Rate Schedules, service under this rate schedule is available in Utilities' electric service territory for any establishment engaged in the operation of a business or an institution, whether or not for profit, whose average daily usage (billing period kWh divided by the number of days in the billing period) is greater than 33 kWh in any of the last 12 billing periods. This rate schedule is not available to Customers whose average daily usage equals or exceeds 1,000 kWh in any of the last 12 billing periods. ~~With the exception for Customers receiving service under the Renewable Energy Net Metering Rate Schedule, unless~~ Unless Utilities determines temporarily establishing service under this option is in the best interest of Utilities, service under this option is frozen to new participation.

RATE OPTIONS

Customers may choose between the following:

A. Frozen Standard Option (E2C)

B. Frozen Time-of-Day Option (ETC)

RATE

See Rate Table for applicable charges.

ELECTRIC RATE SCHEDULES

COMMERCIAL SERVICE – MEDIUM 10 ~~K~~kW MINIMUM (ECM, ECM-P, ECMNM)

AVAILABILITY

As provided in the Energy-Wise, Energy-Wise Plus, and Fixed Seasonal Transition Terms and Conditions of these Electric Rate Schedules, service under this rate schedule is available in Utilities' electric service territory for any establishment engaged in the operation of a business or an institution, whether or not for profit, whose Maximum Demand equals or exceeds 10 kW in any of the last 12 billing periods. This rate schedule is not available to Customers whose Maximum Demand equals or exceeds 50 kW in any of the last 12 billing periods.

RATE OPTIONS

Customers may choose between the following:

A. Energy-Wise Standard Time-of-Day Option (ECM)
Service under this option is not available to Customers who receive service under the ~~Renewable Energy~~ Net Metering Rate Schedule.

B. Energy-Wise Plus Time-of-Day Option (ECM-P)
Service under this option is not available to Customers who: (a) receive service under the ~~Renewable Energy~~ Net Metering Rate Schedule; (b) receive service under the Community Solar Garden Bill Credit (Pilot Program) Rate Schedule, or (c) receive service under the Community Solar Garden Program Rate Schedule.

C. Energy-Wise Net Metering Option (ECMNM)
Service under this option is available to customers receiving service under the Net Metering Rate Schedule.

RATE

See Rate Table for applicable charges.

ELECTRIC RATE SCHEDULES

COMMERCIAL SERVICE – LARGE 50 ~~K~~kW MINIMUM (ECL, ECL-P, ECLNM)

AVAILABILITY

As provided in the Energy-Wise, Energy-Wise Plus, and Fixed Seasonal Transition Terms and Conditions of these Electric Rate Schedules, service under this rate schedule is available in Utilities' electric service territory for any establishment engaged in the operation of a business or an institution, whether or not for profit, whose Maximum Demand equals or exceeds 50 kW in any of the last 12 billing periods. This rate schedule is not available to Customers whose Maximum Demand equals or exceeds 100 kW in any of the last 12 billing periods.

RATE OPTIONS

Customers may choose between the following:

A. Energy-Wise Standard Time-of-Day Option (ECL)
Service under this option is not available to Customers who receive service under the ~~Renewable Energy~~ Net Metering Rate Schedule.

B. Energy-Wise Plus Time-of-Day Option (ECL-P)
Service under this option is not available to Customers who: (a) receive service under the ~~Renewable Energy~~ Net Metering Rate Schedule; (b) receive service under the Community Solar Garden Bill Credit (Pilot Program) Rate Schedule, or (c) receive service under the Community Solar Garden Program Rate Schedule.

C. Energy-Wise Net Metering Option (ECLNM)
Service under this option is available to customers receiving service under the Net Metering Rate Schedule.

RATE

See Rate Table for applicable charges.

ELECTRIC RATE SCHEDULES

FROZEN INDUSTRIAL SERVICE – 1,000 kWh/DAY MINIMUM (ETL, ETLO, ETLW)

AVAILABILITY

As provided in the Energy-Wise, Energy-Wise Plus, and Fixed Seasonal Transition Terms and Conditions of these Electric Rate Schedules, service under this rate schedule is available in Utilities' electric service territory for Customers whose average daily usage (billing period kWh divided by the number of days in the billing period) equals or exceeds 1,000 kWh in any 12-month billing period. This rate is not available to Customers whose Maximum Demand equals or exceeds 500 kW in any of the last 12 billing periods. ~~With the exception for Customers receiving service under the Renewable Energy Net Metering Rate Schedule, unless~~ Unless Utilities determines temporarily establishing service under this option is in the best interest of Utilities, service under this option is frozen to new participation.

RATE OPTIONS

Customers may choose between the following:

A. Frozen Standard Option (ETL)

B. Frozen Non-Demand Summer Option (ETLO)
Available under separate contract, Customers may elect Non-Demand Summer Option. Customers electing this option must consume 75% or more of their 12 billing periods kWh during the Summer period (May through October).

C. Frozen Non-Demand Winter Option (ETLW)
Available under separate contract, Customers may elect Non-Demand Winter Option. Customers electing this option must consume 75% or more of their annual calendar year kWh during the Winter period (November through April).

RATE

See Rate Table for applicable charges.

ELECTRIC RATE SCHEDULES

INDUSTRIAL SERVICE – 100 kW MINIMUM (EIS EIS-P)

AVAILABILITY

As provided in the Energy-Wise, Energy-Wise Plus, and Fixed Seasonal Transition Terms and Conditions of these Electric Rate Schedules, service under this rate schedule is available in Utilities' electric service territory for Customers whose Maximum Demand equals or exceeds 100 kW in any of the last 12 billing periods. Service is not available under this rate schedule for any Customer whose Maximum Demand equals or exceeds 500 kW in any of the last 12 billing periods.

RATE OPTIONS

Customers may choose between the following:

A. Energy-Wise Standard Time-of-Day Option (EIS)
Service under this option is not available to Customers who receive service under the ~~Renewable Energy~~ Net Metering Rate Schedule.

B. Energy-Wise Plus Time-of-Day Option (EIS-P)
Service under this option is not available to Customers who: (a) receive service under the ~~Renewable Energy~~ Net Metering Rate Schedule; (b) receive service under the Community Solar Garden Bill Credit (Pilot Program) Rate Schedule, or (c) receive service under the Community Solar Garden Program Rate Schedule.

RATE

See Rate Table for applicable charges.

ELECTRIC RATE SCHEDULES

INDUSTRIAL SERVICE – 500 kW MINIMUM (E8T, E8T-P)

AVAILABILITY

As provided in the Energy-Wise, Energy-Wise Plus, and Fixed Seasonal Transition Terms and Conditions of these Electric Rate Schedules, service under this rate schedule is available in Utilities' electric service territory for Customers whose Maximum Demand equals or exceeds 500 kW in any of the last 12 billing periods. Service is not available under this rate schedule for any Customer whose Maximum Demand equals or exceeds 4,000 kW in any of the last 12 billing periods.

RATE OPTIONS

Customers may choose between the following:

A. Energy-Wise Standard Time-of-Day Option (E8T)

B. Energy-Wise Plus Time-of-Day Option (E8T-P)
Service under this option is not available to Customers who: (a) receive service under the ~~Renewable Energy~~ Net Metering Rate Schedule; (b) receive service under the Community Solar Garden Bill Credit (Pilot Program) Rate Schedule, or (c) receive service under the Community Solar Garden Program Rate Schedule.

RATE

See Rate Table for applicable charges.

ELECTRIC RATE SCHEDULES

INDUSTRIAL SERVICE – 4,000 kW MINIMUM (E8S, E8S-P)

AVAILABILITY

As provided in the Energy-Wise, Energy-Wise Plus, and Fixed Seasonal Transition Terms and Conditions of these Electric Rate Schedules, service under this rate schedule is available in Utilities' electric service territory for Customers whose Maximum Demand equals or exceeds 4,000 kW in any of the last 12 billing periods. Service is not available under this rate schedule for any Customer whose Maximum Demand equals or exceeds 10,000 kW in any of the last 12 billing periods or whose Maximum Demand is reasonably expected to equal or exceed 10,000 kW in any billing period in the next 120 billing periods.

RATE OPTIONS

Customers may choose between the following:

A. Energy-Wise Standard Time-of-Day Option (E8S)

B. Energy-Wise Plus Time-of-Day Option (E8S-P)
Service under this option is not available to Customers who: (a) receive service under the ~~Renewable Energy~~ Net Metering Rate Schedule; (b) receive service under the Community Solar Garden Bill Credit (Pilot Program) Rate Schedule, or (c) receive service under the Community Solar Garden Program Rate Schedule.

RATE

See Rate Table for applicable charges.

ELECTRIC RATE SCHEDULES

INDUSTRIAL SERVICE – LARGE POWER AND LIGHT (ELG, ELG-P)

AVAILABILITY

Available by contract in Utilities' electric service territory for the Customers whose aggregated Maximum Demand equals or exceeds 4,000 kW in any of the last 12 billing periods. Service is not available under this rate schedule for any Customer whose Maximum Demand equals or exceeds 10,000 kW in any of the last 12 billing periods or whose Maximum Demand is reasonably expected to equal or exceed 10,000 kW in any billing period in the next 120 billing periods. Demand aggregation may only be performed for contiguous service properties on a Customer campus setting. Customers must maintain an annual load factor of 75% or greater.

Annual load factor is derived by multiplying the annual kWh in the period by 100 and dividing by the product of the maximum real demand (prior to power factor correction) in kW and the number of hours in the period. Annual reviews will be conducted by Utilities at the end of the Customer's annual contract period. Annual kWh will be adjusted for Customers receiving service under the Interruptible Service Rate Schedule.

Customers who select this service will be required to provide a suitable location for the aggregation equipment. Totalization charges do not apply to this offering.

RATE OPTIONS

Customers may choose between the following:

A. Energy-Wise Standard Option (ELG)

B. Energy-Wise Plus Time-of-Day Option (ELG-P)
   Service under this option is not available to Customers who: (a) receive service under the ~~Renewable Energy~~ Net Metering Rate Schedule; (b) receive service under the Community Solar Garden Bill Credit (Pilot Program) Rate Schedule, or (c) receive service under the Community Solar Garden Program Rate Schedule.

RATE

See Rate Table for applicable charges.

ELECTRIC RATE SCHEDULES

CONTRACT SERVICE – MILITARY (ECD, ECD-P, EHYDPWR, EINFPRS)

AVAILABILITY

Available by contract in Utilities' electric service territory to the United States of America at the Fort Carson Military Installation, the Peterson Space Force Base, the United States Air Force Academy, and the Cheyenne Mountain Space Force Station.

RATE OPTIONS

Customers may choose between the following:

A. Energy-Wise Standard Time-of-Day Option (ECD)

B. Energy-Wise Plus Time-of-Day Option (ECD-P)
Service under this option is not available to Customers who: (a) receive service under the ~~Renewable Energy~~ Net Metering Rate Schedule; (b) receive service under the Community Solar Garden Bill Credit (Pilot Program) Rate Schedule, or (c) receive service under the Community Solar Garden Program Rate Schedule.

RATE

See Rate Table for applicable charges.

ADDITIONAL SERVICES

In addition to the standard Contract Service to the listed military installations:

A. Military Hydroelectric Power Sales Service (EHYDPWR) is available by contract to the United States of America at the Fort Carson Military Installation for sales of electric energy for transmission over Utilities' electric system for final consumption within the geographic confines of the Fort Carson Military Installation.

B. On-site, Direct-service Solar Contract Service – USAFA (EINFPRS) is available by contract to the United States of America at the United States Air Force Academy for solar energy electric service provided from solar electric generating facilities located within the geographic confines of the United States Air Force Academy and with direct electric service from those solar electric generating facilities provided to the United States Air Force Academy.

ELECTRIC RATE SCHEDULES

~~RENEWABLE ENERGY~~ NET METERING

AVAILABILITY

Available by contract in Utilities' service territory to Customers whose electric service is supplied by Utilities under any rate schedule, except as otherwise provided in these Electric Rate Schedules.

APPLICABILITY

Service under this rate schedule will be provided to Customers that either:

A. install an eligible Renewable Energy System and execute a Utilities' Interconnection Agreement (Agreement) to participate in the Net Metering Program (Program), or

B. lease an eligible Renewable Energy System located at their residence or business and elect to participate in the Program, and the owner of the eligible Renewable Energy System executes an Agreement.

The Program is available to Customers who either: a) own, operate, and maintain in parallel with Utilities' electric system an eligible Renewable Energy System, or b) lease an eligible Renewable Energy System and the owner of that system operates and maintains the system in parallel with Utilities' electric system.

The eligible Renewable Energy System, as defined in Section 40-2-124, C.R.S., may not be sized larger than 120% of the Customer's annual kilowatt-hour usage, actual or, at Utilities' discretion estimated. The photovoltaic generation system or other approved eligible Renewable Energy System will be limited to a maximum design capacity of 15 kW alternating current (AC) for Residential Customers and 150 kW AC for Commercial and Industrial Customers. Systems with a design capacity in excess of 150 kW AC for Commercial and Industrial Customers may be considered and are subject to approval by Utilities.

NET METERING

Net Metering is, for billing purposes, the net consumption as measured at Utilities' service meter, such that the renewable energy production need not be separately measured by the service meter other than for informational purposes. In the event that net metering is negative such that the eligible Renewable Energy System production is greater than the Customer's consumption in any month, Utilities will allow excess generation credits (kilowatt-hours) to be carried over and applied to the following month(s).

ELECTRIC RATE SCHEDULES

~~RENEWABLE ENERGY~~ NET METERING

Any excess generation credits accrued will be credited to the Customer's account annually at the Small Power Producers and Cogeneration Service Rate Schedule. Customers receiving service under a rate schedule subject to the Fixed ECA will have credits calculated at the Small Power Producers and Cogeneration Service Rate Schedule as follows: 14% of the On-Peak Rate plus 86% of the Off-Peak Rate. Customers will be billed the applicable per day Access and Facilities Charges each month regardless of excess generation during that month.

RATE

See Rate Table.

The Customer may make a one-time election, in writing, on or before the end of a calendar year, to request that the excess kilowatt-hours be carried forward as a credit from month-to-month indefinitely until the Customer terminates service with Utilities, at which time no payment shall be required from Utilities for any remaining excess kilowatt hour credits supplied by the Customer.

All electric power and energy delivered by Utilities to the Customer under this rate schedule will be received and paid for by the Customer at the applicable Residential, Commercial or Industrial Service Rate Schedule. All applicable Access and Facilities charges, ECA and ECC will apply.

RENEWABLE ENERGY CREDITS

Renewable Energy Credits as referenced in Section 40-2-124.1(d), C.R.S., are the environmental attributes of renewable energy generation. A Renewable Energy Credit represents one MWh of renewable energy that is physically metered and verified. If a rebate or an incentive payment has been made by Utilities to the Customer, then Utilities shall own all Renewable Energy Credits or other environmental attributes generated under this tariff as provided for in the policies, rules, and agreement related to the rebate or incentive program and that are accepted by the Customer.

ELECTRIC RATE SCHEDULES

COMMUNITY SOLAR GARDEN PROGRAM

AVAILABILITY

The Community Solar Garden Program (Program) is available under the terms and conditions of this rate schedule to all Customers taking service under Utilities' Electric Rate Schedules with the following exceptions: (a) Energy-Wise Plus Time-of-Day Peak Options (ETR-P, ECS-P, ECM-P, ECL-P, EIS-P, E8T-P, E8S-P, ELG-P, ECD-P), (b) Commercial Service – Non-Metered (ENM), (c) Contract Service – Military Wheeling (ECW), (d) Contract Service – Traffic Signals (E2T), (e) Contract Service – Street Lighting (E7SL), (f) Electric Cost Adjustment (ECA), (g) Electric Capacity Charge (ECC), (h) Totalization Service, (i) Enhanced Power Service, (j) ~~Renewable Energy~~ Net Metering, (k) Small Power Producers & Cogeneration Service, and (l) Community Solar Garden Bill Credit (Pilot Program). All Customers that participate under this rate schedule must hold evidence of ownership to, a subscription as evidence of beneficial use of, or an entitlement to the electric generating capacity of a Community Solar Garden Facility (Customer Solar Garden Interest). Customers may choose any Community Solar Garden Facility that conforms to this rate schedule.

The choice of a Community Solar Garden Facility and the purchase of a Customer Solar Garden Interest is solely the responsibility of the Customer and are undertaken at the Customer's risk. Utilities makes no representations or warranties concerning the Community Solar Garden Facility and its operation and maintenance and its financial viability or the continued usefulness of any Customer Solar Garden Interest.

COMMUNITY SOLAR GARDEN FACILITY

A Community Solar Garden Facility for purposes of this rate schedule is a photovoltaic electric generating installation having a nameplate rating of not less than 0.5 megawatts Alternating Current (MWAC) and not more than 2.0 MWAC in electric generating capacity and the owning entity that has executed an Interconnection Agreement with Utilities. If the Interconnection Agreement is extended, Utilities will retain the Renewable Energy Credits through the extension period at no additional cost. The physical location of any Community Solar Garden Facility under this rate schedule shall be within the electric service territory of Utilities and any electric power produced by the Community Solar Garden Facility shall be consumed within the electric service territory of Utilities. All costs of interconnection for the Community Solar Garden Facility shall be borne and paid by the legal owner of the Community Solar Garden Facility.

This Program will allow for up to 2.0 MWAC of electric generating capacity to be added to Utilities' portfolio of Distributed Generation resources.

Electric

Final Tariff Sheets

Effective January 1, 2026

ELECTRIC RATE SCHEDULES

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ELECTRIC RATE SCHEDULES

RATE TABLE

Description	Rates (Note)				
	2025	2026	2027	2028	2029
Totalization Service – Sheet No. 18					
For each meter totalized, per meter, per day	$8.0000				
Enhanced Power Service – Sheet No. 19					
Reserved Capacity Charge:					
The greater of On-Peak or Off-Peak Billing Demand or projected peak demand, per kW, per day	$0.0333	$0.0355	$0.0378	$0.0403	$0.0429
Operations & Maintenance Charge:					
See *Line Extension and Service Standards* for Electric for calculation.					

Note: 2025 rates are effective October 1, 2025. All other rates are effective January 1st of the respective year shown. Rates effective 2029 will remain effective until superseded by City Council.

ELECTRIC RATE SCHEDULES
RATE TABLE

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ELECTRIC RATE SCHEDULES

RATE TABLE

Description	Rates (Note)				
	2025	2026	2027	2028	2029
Small Power Producers and Cogeneration Service – Sheet No. 21					
On-Peak, per kWh	$0.0195				
Off-Peak, per kWh	$0.0180				
Community Solar Garden Bill Credit (Pilot Program) – Sheet No. 22					
The rate applicable to each kilowatt hour under the Bill Credit section of this rate schedule	$0.1080	$0.1150	$0.1225	$0.1305	$0.1390
Community Solar Garden Program – Sheet No. 23					
Customer Rate Class – Credit, per kWh					
Residential Service (E1R, ETR, ETR-F)	$0.0654	$0.0697	$0.0742	$0.0790	$0.0841
Commercial Service – Small (E1C)	$0.0585	$0.0623	$0.0663	$0.0706	$0.0752
Commercial Service – Small (ECS, ECS-F)	$0.0591	$0.0629	$0.0670	$0.0714	$0.0760
Commercial Service – General (E2C)	$0.0586	$0.0624	$0.0665	$0.0708	$0.0754
Commercial Service – General Time-of-Day Option (ETC)	$0.0586	$0.0624	$0.0665	$0.0708	$0.0754
Commercial Service – Medium 10 kW Minimum (ECM)	$0.0585	$0.0623	$0.0663	$0.0706	$0.0752
Commercial Service – Large 50 kW Minimum (ECL)	$0.0564	$0.0601	$0.0640	$0.0682	$0.0726
Industrial Service – 1,000 kWh/Day Minimum (ETL)	$0.0541	$0.0576	$0.0613	$0.0653	$0.0695
Industrial Service – 100 kW Minimum (EIS)	$0.0549	$0.0585	$0.0623	$0.0663	$0.0706
Industrial Service – 500 kW Minimum (E8T)	$0.0514	$0.0547	$0.0583	$0.0621	$0.0661
Industrial Service – 4,000 kW Minimum (E8S)	$0.0507	$0.0540	$0.0575	$0.0612	$0.0652
Industrial Service – Large Power and Light (ELG)	$0.0443	$0.0472	$0.0503	$0.0536	$0.0571
Industrial Service – Time-of-Day Transmission Voltage (ETX)	$0.0578	$0.0616	$0.0656	$0.0699	$0.0744
Contract Service – Military (ECD)	$0.0517	$0.0551	$0.0587	$0.0625	$0.0666

Note: 2025 rates are effective October 1, 2025. All other rates are effective January 1st of the respective year shown. Rates effective 2029 will remain effective until superseded by City Council.

ELECTRIC RATE SCHEDULES

RATE TABLE

Description	Rates (Note)				
	2025	2026	2027	2028	2029
Electric Vehicle Public Charging Service – Time-of-Day – Sheet No. 25					
Level 2					
On-Peak, per kWh	$0.3600	$0.3800	$0.4000	$0.4300	$0.4600
Off-Peak, per kWh	$0.1300	$0.1400	$0.1500	$0.1600	$0.1700
Idle Rate, per minute	$0.1100	$0.1200	$0.1300	$0.1400	$0.1500
Idle rate is applicable beginning 15 minutes after charge is complete.					
Direct Current Fast Charger (DCFC)					
On-Peak, per kWh	$0.5800	$0.6200	$0.6600	$0.7000	$0.7500
Off-Peak, per kWh	$0.2000	$0.2100	$0.2200	$0.2300	$0.2400
Idle Rate, per minute	$0.3200	$0.3400	$0.3600	$0.3800	$0.4000
Idle rate is applicable beginning 15 minutes after charge is complete.					
Interruptible Service – Sheet No. 26					
Demand Credit, per kW, per day	$0.1233				
Energy Credit, per kWh	$0.4500				

Note: 2025 rates are effective October 1, 2025. All other rates are effective January 1st of the respective year shown. Rates effective 2029 will remain effective until superseded by City Council.

ELECTRIC RATE SCHEDULES

RATE TABLE

Description	Rates (Note)			
	2026	2027	2028	2029
Industrial Service – Large Load (ELL) – Sheet No. 27				
Access and Facilities Charge, per day	$8.9065	$9.9664	$11.1524	$12.4795
Demand Charge Secondary, per kW, per day	$0.8593	$0.9616	$1.0760	$1.2040
System Support Charge, per kW, per day	$0.0859	$0.0962	$0.1076	$0.1204
Resource Adequacy Charge, per kW, per day	$0.4110	$0.4377	$0.4662	$0.4965
Purchased Energy Charge, per kWh	By Contract			
Purchased Capacity Charge, per kW, per day	By Contract			
Electric Cost Adjustment (ECA), per kWh	Sheet No. 2.17			
Electric Capacity Charge (ECC), per kWh	Sheet No. 2.18			

Note: All rates are effective January 1st of the respective year shown. Rates effective 2029 will remain effective until superseded by City Council.

ELECTRIC RATE SCHEDULES

GENERAL

DEMAND DETERMINATIONS

Commercial Service (ECM, ECM-P, ECL, ECL-P)

Maximum Demand and/or Billing Demand:

Greatest 15-minute load during any block of time in the billing period.

Industrial and Contract Service

Maximum Demand (ETL, EIS, EIS-P, E8T, E8T-P, E8S, E8S-P, ELG, ELG-P, ETX, ECD, ECD-P, ELL)

Maximum Demand is the greatest 15-minute load during any time in the billing period adjusted upward by 1% for each 1% that the power factor of Customer is below 95% lagging or leading.

Billing Demand

Energy-Wise Standard Time-of-Day Option (ETL, EIS, E8T, E8S, ELG, ETX, ECD)

On-Peak:

The greatest 15-minute load during On-Peak hours in the billing period adjusted upward by 1% for each 1% that the power factor of Customer is below 95% lagging or leading.

Off-Peak: either A or B, whichever is greater.

A. The greatest 15-minute load during Off-Peak hours in the billing period adjusted upward by 1% for each 1% that the power factor of Customer is below 95% lagging or leading, minus the
On-Peak Billing Demand. Such demand will not be less than zero.

B. 68% of the Maximum Demand during the last 12 billing periods, minus the On-Peak Billing Demand. Such demand will not be less than zero. Part B of Off-Peak Billing Demand is not applicable to Industrial Service – Transmission Voltage (ETX).

Energy-Wise Plus Time-of-Day Peak Option (EIS-P, E8T-P, E8S-P, ELG-P, ECD-P)

Demand:

The greatest 15-minute load during any time in the billing period adjusted upward by 1% for each 1% that the power factor of Customer is below 95% lagging or leading.

Industrial Service – Large Load (ELL) see Sheet No. 27.1

ELECTRIC RATE SCHEDULES
GENERAL

TRANSMISSION AND PRIMARY SERVICE DEMAND CHARGE CREDIT

Transmission Service Demand Charge Credit

A Transmission Service Demand Charge Credit of $0.2738 per kW, per day will be applied to the Demand Charge Secondary for Customers receiving electric transmission service under the Industrial Service – Large Load (ELL) Rate Schedule. The credit is not applicable to all other kW, per day charges.

Primary Service Demand Charge Credit

A Primary Service Demand Charge Credit of $0.0118 per kW, per day will be applied to all applicable Demand Charges for Customers receiving electric primary service.

RATE OPTIONS

Residential and Commercial Service – Small (ETR-F, ETR-P, ECS-F, ECS-P)

Rate options will be for a minimum twelve (12) consecutive billing periods.

All Other Rate Schedules

Customers may elect a rate option as more fully set forth on subsequent Electric Rate Schedules subject to any applicable separate eligibility and contract requirements as noted. Unless otherwise noted, the initial contract period is from the rate option service start date to December 31st. Unless otherwise stated and as long as the Customer continues to meet the eligibility requirements, the rate option service contract shall be automatically renewed for an additional 12-month contract period each January 1st unless Customer provides advance written notice to Utilities not less than 30 days prior to the January 1st renewal date that Customer elects not to renew for the upcoming rate option contract year. Customers will be evaluated periodically to ensure they continue to meet the specified rate option eligibility requirements. In the event that a Customer is no longer eligible, the contract for rate option service shall not be renewed and shall automatically terminate at the end of the 12-month contract period on December 31st. Upon termination, Customer shall be required to move to the rate schedule to which they are eligible upon the end of the contract period.

TIME-OF-DAY PERIODS

On-Peak Periods are Monday through Friday excluding the holidays as defined below. Unless otherwise provided On-Peak periods are as follows:

On-Peak Periods (excluding ETC, ETL)

January through December: 5:00 p.m. to 9:00 p.m.

Frozen Time-of-Day Service On-Peak Periods (ETC, ETL)

Winter (October through March): 4:00 p.m. to 10:00 p.m.
Summer (April through September): 11:00 a.m. to 6:00 p.m.

ELECTRIC RATE SCHEDULES

COMMERCIAL SERVICE – SMALL (ECS, ECS-P, ECS-F)

AVAILABILITY

As provided in the Energy-Wise, Energy-Wise Plus, and Fixed Seasonal Transition Terms and Conditions of these Electric Rate Schedules, service under this rate schedule is available in Utilities' electric service territory for any establishment engaged in the operation of a business or an institution, whether or not for profit, whose Maximum Demand is less than 10 kW in each of the last 12 billing periods.

RATE OPTIONS

Customers may choose between the following:

A. Energy-Wise Standard Time-of-Day Option (ECS)
Service under this option is not available to Customers who receive service under the Renewable Energy Net Metering Rate Schedule.

B. Energy-Wise Plus Time-of-Day Option (ECS-P)
Service under this option is not available to Customers who: (a) receive service under the Renewable Energy Net Metering Rate Schedule; (b) receive service under the Community Solar Garden Bill Credit (Pilot Program) Rate Schedule, or (c) receive service under the Community Solar Garden Program Rate Schedule.

C. Fixed Seasonal Option (ECS-F)
Service under this option is not available to customers receiving service under the Renewable Energy Net Metering Rate Schedule.

RATE

See Rate Table for applicable charges.

ELECTRIC RATE SCHEDULES

INDUSTRIAL SERVICE – 4,000 kW MINIMUM (E8S, E8S-P)

AVAILABILITY

As provided in the Energy-Wise, Energy-Wise Plus, and Fixed Seasonal Transition Terms and Conditions of these Electric Rate Schedules, service under this rate schedule is available in Utilities' electric service territory for Customers whose Maximum Demand equals or exceeds 4,000 kW in any of the last 12 billing periods. Service is not available under this rate schedule for any Customer whose Maximum Demand equals or exceeds 10,000 kW in any of the last 12 billing periods or whose Maximum Demand is reasonably expected to equal or exceed 10,000 kW in any billing period in the next 120 billing periods.

RATE OPTIONS

Customers may choose between the following:

A. Energy-Wise Standard Time-of-Day Option (E8S)

B. Energy-Wise Plus Time-of-Day Option (E8S-P)
Service under this option is not available to Customers who: (a) receive service under the Renewable Energy Net Metering Rate Schedule; (b) receive service under the Community Solar Garden Bill Credit (Pilot Program) Rate Schedule, or (c) receive service under the Community Solar Garden Program Rate Schedule.

RATE

See Rate Table for applicable charges.

ELECTRIC RATE SCHEDULES
INDUSTRIAL SERVICE – LARGE POWER AND LIGHT (ELG, ELG-P)

AVAILABILITY

Available by contract in Utilities' electric service territory for the Customers whose aggregated Maximum Demand equals or exceeds 4,000 kW in any of the last 12 billing periods. Service is not available under this rate schedule for any Customer whose Maximum Demand equals or exceeds 10,000 kW in any of the last 12 billing periods or whose Maximum Demand is reasonably expected to equal or exceed 10,000 kW in any billing period in the next 120 billing periods. Demand aggregation may only be performed for contiguous service properties on a Customer campus setting. Customers must maintain an annual load factor of 75% or greater.

Annual load factor is derived by multiplying the annual kWh in the period by 100 and dividing by the product of the maximum real demand (prior to power factor correction) in kW and the number of hours in the period. Annual reviews will be conducted by Utilities at the end of the Customer's annual contract period. Annual kWh will be adjusted for Customers receiving service under the Interruptible Service Rate Schedule.

Customers who select this service will be required to provide a suitable location for the aggregation equipment. Totalization charges do not apply to this offering.

RATE OPTIONS

Customers may choose between the following:

A. Energy-Wise Standard Option (ELG)

B. Energy-Wise Plus Time-of-Day Option (ELG-P)
   Service under this option is not available to Customers who: (a) receive service under the Renewable Energy Net Metering Rate Schedule; (b) receive service under the Community Solar Garden Bill Credit (Pilot Program) Rate Schedule, or (c) receive service under the Community Solar Garden Program Rate Schedule.

RATE

See Rate Table for applicable charges.

ELECTRIC RATE SCHEDULES

FROZEN INDUSTRIAL SERVICE – TIME-OF-DAY TRANSMISSION VOLTAGE (ETX)

AVAILABILITY

Available in Utilities' electric service territory for any Customer who has provided, installed, and maintains transformer(s) to receive three-phase, 60-hertz, alternating current electrical service at a nominal potential of 115,000 or 230,000 volts on the Customer's Premise. The Customer may be required to execute a contract with additional terms and conditions should service to the Customer under this rate schedule require any material change to Utilities' plant in service or operations. Unless Utilities determines temporarily establishing service under this rate schedule is in the best interest of Utilities, service under this rate schedule is frozen to new participation.

The Customer will provide, install, and maintain necessary switches, cutouts, protection equipment and the necessary wiring on the primary and secondary sides of the transformer(s). All equipment required to receive service that is installed and maintained by the Customer will be subject to approval by Utilities prior to installation and inspection or testing thereafter.

RATE

See Rate Table for applicable charges.

AVAILABILITY

The Community Solar Garden Program (Program) is available under the terms and conditions of this rate schedule to all Customers taking service under Utilities' Electric Rate Schedules with the following exceptions: (a) Energy-Wise Plus Time-of-Day Peak Options (ETR-P, ECS-P, ECM-P, ECL-P, EIS-P, E8T-P, E8S-P, ELG-P, ECD-P), (b) Commercial Service – Non-Metered (ENM), (c) Contract Service – Military Wheeling (ECW), (d) Contract Service – Traffic Signals (E2T), (e) Contract Service – Street Lighting (E7SL), (f) Electric Cost Adjustment (ECA), (g) Electric Capacity Charge (ECC), (h) Totalization Service, (i) Enhanced Power Service, (j) Renewable Energy Net Metering, (k) Small Power Producers & Cogeneration Service, and (l) Community Solar Garden Bill Credit (Pilot Program). All Customers that participate under this rate schedule must hold evidence of ownership to, a subscription as evidence of beneficial use of, or an entitlement to the electric generating capacity of a Community Solar Garden Facility (Customer Solar Garden Interest). Customers may choose any Community Solar Garden Facility that conforms to this rate schedule.

The choice of a Community Solar Garden Facility and the purchase of a Customer Solar Garden Interest is solely the responsibility of the Customer and are undertaken at the Customer's risk. Utilities makes no representations or warranties concerning the Community Solar Garden Facility and its operation and maintenance and its financial viability or the continued usefulness of any Customer Solar Garden Interest.

COMMUNITY SOLAR GARDEN FACILITY

A Community Solar Garden Facility for purposes of this rate schedule is a photovoltaic electric generating installation having a nameplate rating of not less than 0.5 megawatts Alternating Current (MWAC) and not more than 2.0 MWAC in electric generating capacity and the owning entity that has executed an Interconnection Agreement with Utilities. If the Interconnection Agreement is extended, Utilities will retain the Renewable Energy Credits through the extension period at no additional cost. The physical location of any Community Solar Garden Facility under this rate schedule shall be within the electric service territory of Utilities and any electric power produced by the Community Solar Garden Facility shall be consumed within the electric service territory of Utilities. All costs of interconnection for the Community Solar Garden Facility shall be borne and paid by the legal owner of the Community Solar Garden Facility.

This Program will allow for up to 2.0 MWAC of electric generating capacity to be added to Utilities' portfolio of Distributed Generation resources.

ELECTRIC RATE SCHEDULES
INDUSTRIAL SERVICE – LARGE LOAD (ELL)

AVAILABILITY

Available by contract in Utilities' electric service territory for any Customer whose Maximum Demand equals or exceeds 10,000 kW in any of the last 12 billing periods, or whose Maximum Demand is reasonably expected to equal or exceed 10,000 kW in any billing period in the next 120 billing periods. If aggregation of loads is permitted by Utilities pursuant to the terms provided in this rate schedule, the Maximum Demand used for the purpose of determining availability under this rate schedule will be based on the aggregated Maximum Demand. Customers with common owner(s) or parent companies operating within a contiguous site will have loads aggregated for determining the Maximum Demand for the purposes of determining availability under this rate schedule.

SERVICE CONSIDERATIONS

A. Customers must submit a completed signed Large Load Service Agreement (LLSA) and pay all applicable fees and charges in order to qualify for service under this rate schedule. The LLSA shall specify provisions of service including the following but not limited to: annual load and energy requirements, load characteristics, construction related terms, operating procedures, the date of service availability, and administrative terms and conditions. The initial term of the LLSA will be established in the agreement but not be less than 10 years. Customers meeting the collateral waiver requirements as provided in this Rate Schedule are deemed to have completed the initial LLSA term.

B. Upon Utilities joining a Regional Transmission Organization (RTO), service under this rate schedule will be contingent upon and subject to the RTO's tariff provisions, and the Customer will be responsible for any cost incurred related to studies, interconnection, and service of the Customer's load.

C. Availability and terms of service are subject to Utilities and any applicable RTO study results and requirements. Interim service may be contingent upon the Customer being subject to interruption or curtailment under any applicable Utilities and/or RTO tariffs.

D. If extension or modification of Utilities' transmission system is required to provide service, the Customer shall be responsible for the cost of required extensions or modifications as set forth in Utilities' Rules and Regulations.

E. Customers must provide, install, and maintain transformer(s) to receive three-phase, 60-hertz, alternating current electrical service at nominal potential of 115,000 or 230,000 volts on the Customer Premise. Alternatively, where Utilities determines serving Customers through Utilities' substation facilities is in the best interest, Customers shall pay the applicable Substation Facility Fees as set forth in Utilities' Rules and Regulations. Customers paying the Substation Facility Fees must provide, install, and maintain equipment to receive Primary or Secondary Service as provided in Utilities' Rules and Regulations and in accordance with the *Line Extension and Service Standards* for Electric.

F. Service will generally be provided through one meter unless Utilities, in its sole discretion, determines additional meters and aggregation is warranted. The aggregation terms and conditions set forth in the Industrial Service – Large Power and Light (ELG) Rate Schedule will apply.

G. If in Utilities determination, the Customers load cannot be served by Utilities existing capabilities, the Customer will be served on an interim basis through market agreement(s) for capacity and energy requirements for a period of time not to exceed the 10-year term of the initial LLSA. In lieu of ECA and ECC charges, Utilities will bill the Customer the full costs of the market agreement(s) through charges as set forth in the LLSA and these Electric Rate Schedules.

H. Except for Customers whose collateral requirements have been waived pursuant to the terms provided in this rate schedule below, Customers will be subject to the Resource Adequacy Charge and the System Support Charge, as set forth in these Electric Rate Schedules, for each billing period in the initial 10-year term of the LLSA.

I. If at any time the Customer's actual maximum demand exceeds the contracted annual load requirements, the Customer shall provide an updated annual load requirement and the LLSA shall be updated to reflect the higher demand.

J. Utilities has no obligation to serve loads in excess of the contracted demand for the calendar year as provided in the LLSA.

DEMAND AND ENERGY DETERMINATIONS

A. During the initial 10-year LLSA period, Billing Demand will be the highest of (1) the greatest 15-minute load in the billing period adjusted upward by 1% for each 1% that the power factor of Customer is below 95% lagging or leading, (2) 100% of the Maximum Demand occurring during the last 12 billing periods, or (3) 100% of the contracted demand for the calendar year as provided in the LLSA.

B. After the initial 10-year LLSA period, Billing Demand will be the highest of the greatest 15-minute load in the billing period adjusted upward by 1% for each 1% that the power factor of Customer is below 95% lagging or leading, or 68% of the Maximum Demand occurring during the last 12 billing periods.

C. During the initial 10-year LLSA period, Billing Energy will be the higher of metered energy for the billing period, or contracted monthly energy as set forth in market agreement and the LLSA.

D. After the initial 10-year LLSA period, Billing Energy will be equal to the metered energy for the billing period.

MINIMUM MONTHLY BILL

The Minimum Monthly Bill will be the sum of applicable Access and Facilities, Demand, Generation Capacity Charge, System Support Charge, market agreement charges, ECA, ECC, and all other applicable charges calculated using the Billing Demand, Billing Energy, and other applicable billing determinates as defined in these Electric Rate Schedules, Utilities' Rules and Regulations, and the LLSA.

COLLATERAL REQUIREMENT DETERMINATION

A. The collateral requirement under this rate schedule is in place of the Electric portion of deposits for starting service under Utilities' Rules and Regulations. Deposits relating to starting service for Natural Gas, Water, and Wastewater services provided by Utilities shall apply as provided in Utilities' Rules and Regulations and Utilities' Tariffs.

B. The collateral requirement is equal to the highest 36 months of estimated Minimum Monthly Bills occurring during the LLSA term. Estimation of the highest 36 monthly bills will be calculated using the demand and energy requirements as provided in the LLSA.

C. If during the LLSA term the annual load or energy requirements increase from those provided in the initial agreement, additional collateral will be required such that the total collateral requirement equals the highest 36 months of estimated bills for the service contract based on the updated annual load and energy requirements.

D. The Customer must provide the collateral requirement in one or more of the following forms:
   1. Cash for the full collateral requirement. Interest will not be accrued on cash collateral; or

   2. A standby irrevocable Letter of Credit (LOC) for the full collateral requirement. The LOC must be issued by a U.S. bank or the U.S. branch of a foreign bank, which is not affiliated with the

Customer, with a credit rating of at least A- from Standard & Poor's (S&P) and A3 from Moody's, as well as a minimum capitalization of at least $250 million. Such security must be issued for a minimum term of 360 days. The Customer must cause the renewal or extension of the security for additional consecutive terms of 360 days or more no later than 30 days prior to each expiration date of the security through the entire service contract term and provide Utilities written notice of such renewal. If the security is not renewed or extended as required herein, Utilities will have the right to draw immediately upon the LOC and be entitled to hold the amounts so drawn as security. The LOC must be in a format acceptable to and approved by Utilities.

E. Utilities may waive collateral requirements for Customers who have maintained service under an Industrial Service Rate Schedule for the preceding 120 billing periods, and each of the following conditions apply:

1. The Customer has not had any delinquency within the preceding 120 billing periods; and

2. The Customer's maximum rolling 12-month load to rolling 12-month average load ratio has not exceeded 1.20 in any month in the preceding 120 billing periods; and

3. The Customer's load is not expected to increase by more than 5 MW within the next 120 billing periods; and

4. In the event of merger, acquisition, or legal transfer of interest or other event causing a change in the Customer name and/or identification, the Customer demonstrates successorship in interest from the predecessor to the successor entity.

5. If circumstances related to Utilities' prior waiver of collateral requirements change and are no longer applicable, the collateral requirement will be immediately due.

TERMS AND CONDITIONS

A. During the term of the LLSA the Customer may terminate service by providing written notice to Utilities no less than 36 months prior to the requested service end date. The LLSA will automatically renew for an additional 36 months at the end of each LLSA term unless Customer provides advance written notice of termination no less than 36 months prior to expiration.

B. Upon termination the Customer is responsible for paying a LLSA Termination Fee equal to the estimated Minimum Monthly Bills remaining in the LLSA term or the highest 36 months of estimated Minimum Monthly Bills occurring during the LLSA, whichever is greater.

C. 36 months prior to LLSA renewal, Utilities or the Customer may request modification of the load and energy requirement.

RATE

See Rate Table for applicable charges.

PAYMENT

Payment of billing statements is due and payable by the date indicated in the billing statement. If full payment of charges is not made on or prior to the due date, a late payment fee of 1.5% per month will be assessed on the overdue balance. Collateral requirements will be called when Utilities initiates Discontinuance of Service by Utilities for Failure to Pay When Due as provided in Utilities Rules and Regulations.

Electric

Final Tariff Sheets

Effective April 1, 2026

ELECTRIC RATE SCHEDULES

RATE TABLE

Description	Rates (Note)				
	2025	2026	2027	2028	2029
Summer (June – September), per kW, per day	$0.0366	$0.0390	$0.0415	$0.0442	$0.0471
Access and Facilities Charge:					
Winter (October – May) On-Peak, per kWh	$0.0407	$0.0433	$0.0461	$0.0491	$0.0523
Winter (October – May) Off-Peak, per kWh	$0.0276	$0.0294	$0.0313	$0.0333	$0.0355
Winter (October – May) Off-Peak Saver, per kWh	$0.0114	$0.0121	$0.0129	$0.0137	$0.0146
Summer (June – September) On-Peak, per kWh	$0.1293	$0.1377	$0.1467	$0.1562	$0.1664
Summer (June – September) Off-Peak, per kWh	$0.0276	$0.0294	$0.0313	$0.0333	$0.0355
Summer (June – September) Off-Peak Saver, per kWh	$0.0142	$0.0151	$0.0161	$0.0171	$0.0182
Critical Peak Period (During Event Hours), per kWh	$0.4578	$0.4876	$0.5193	$0.5531	$0.5891
Electric Cost Adjustment (ECA):					
On-Peak, per kWh	Sheet No. 2.17				
Off-Peak, per kWh	Sheet No. 2.17				
Off-Peak Saver, per kWh	Sheet No. 2.17				
Electric Capacity Charge (ECC), per kWh	Sheet No. 2.18				
Optional Service (EHYDPWR, EINFPRS)					
See rate and charge detail in tariff					
Contract Service – Military Wheeling (ECW) – Sheet No. 13					
Required Services					
Wheeling Demand Charge, per kW, per day	$0.0806	$0.2009	$0.2140	$0.2279	$0.2427
Contract Service – Traffic Signals (E2T) – Sheet No. 14					
Access and Facilities Charge, per day	$0.5135	$0.5613	$0.6135	$0.6706	$0.7330
Access and Facilities Charge, per kWh	$0.0949	$0.1037	$0.1133	$0.1238	$0.1353
Electric Cost Adjustment (ECA), per kWh	Sheet No. 2.17				
Electric Capacity Charge (ECC), per kWh	Sheet No. 2.18				

Note: 2025 rates are effective October 1, 2025. 2026 ECW rate is effective starting April 1, 2026. All other rates are effective January 1st of the respective year shown. Rates effective 2029 will remain effective until superseded by City Council.

ELECTRIC RATE SCHEDULES
CONTRACT SERVICE – MILITARY WHEELING (ECW)

AVAILABILITY

Available by contract in Utilities' electric service territory to the United States of America at the Peterson Space Force Base, the Cheyenne Mountain Space Force Station, the United States Air Force Academy and the Fort Carson Military Installation. Service under this rate schedule is not available to any other Customer or entity.

Service is offered at the request of Customer so that Customer may purchase an allocated portion of its power and energy requirements from the Western Area Power Administration (Western). Service is also offered at the request of Customer to allow the Fort Carson Military Installation (Fort Carson) to purchase a portion of its power and energy requirements from Utilities under Contract Service – Military (EHYDPWR) (Hydro Power tariff). These Customer purchases from Western or from Utilities will be under a long-term contract for firm capacity and associated energy. Utilities will wheel (transport), subject to available capacity, such energy over Utilities' transmission and distribution systems to Customer's facility. Electric requirements of the Customer in excess of its allocation from Western or in excess of its purchases under the Hydro Power tariff will be supplied by Utilities as supplemental power and energy.

APPLICABILITY

Service under this rate schedule will be provided only if a contract for such service is in effect between Customer and Utilities. Services other than distribution wheeling provided to Customer by Utilities are limited to services set forth within this rate schedule and separately contracted for by Customer. Services provided by Utilities under this rate schedule are strictly limited to power and energy requirements of each Customer within its boundaries. Under no circumstances will Customer resell any power and/or energy provided under this rate schedule, or use in any way such power or energy outside the confines of Customer's facility.

REQUIRED SERVICES

Customer must contract for the following services:

A. Wheeling

B. Supplemental Power and Energy

ELECTRIC RATE SCHEDULES

CONTRACT SERVICE – MILITARY WHEELING (ECW)

Wheeling

Wheeling is defined as the transporting of power and energy over Utilities' transmission and distribution system for redelivery of Customer's allocated portion of its power and energy from Western or for Customer's purchase of power and energy from Utilities under the Hydro Power tariff. This rate schedule pertains to wheeling over Utilities' transmission and distribution system. Customer must furnish to Utilities copies of contracts and/or agreements between Customer and Western, and between Customer and any intermediate wheeling source. Utilities will maintain copies of Customer's purchases under the Hydro Power tariff. Wheeling availability is always subject to capacity constraints of Utilities' transmission and distribution system and any intermediate wheeling parties' transmission limitations. When Utilities identifies a transmission capacity constraint, Utilities agrees to provide notice to the Customer and to work with the Customer in developing an alternative transmission arrangement.

This service is contingent upon the availability of a transmission and distribution wheeling path from the point of interconnection to Customer's facility. Wheeling will be provided if and when capacity is available above the needs of Utilities' firm Customers.

This service is available to Customer for power and energy purchased from Western and delivered to Utilities' points of interconnection pursuant to a contract between Customer and Utilities. This service is also available to Customer for power and energy purchases from Utilities under the Hydro Power tariff and delivered to Customer. Absent physical or safety constraints, Utilities will redeliver all of Customer's power and energy scheduled and delivered from Western (or purchased by Customer from Utilities under the Hydro Power tariff) to Utilities' points of interconnection with Customer. Utilities shall not be liable for failing to deliver power to Customer either because of interruption of scheduled deliveries from Western (or interruption of deliveries under the Hydro Power tariff) or malfunctions within Utilities' transmission and distribution system or interruptions of wheeling service by intermediate wheeling parties.

Electric

Final Tariff Sheets

Effective January 1, 2027

ELECTRIC RATE SCHEDULES

TABLE OF CONTENTS

DESCRIPTION **SHEET NO.**

ELECTRIC RATE SCHEDULES

RATE TABLE

Description	Rates (Note)				
	2025	2026	2027	2028	2029
Summer (June – September) Off-Peak, per kWh	$0.0730	$0.0777	$0.0827	$0.0880	$0.0936
Summer (June – September) Off-Peak Saver, per kWh	$0.0517	$0.0550	$0.0585	$0.0622	$0.0662
Critical Peak Period (During Event Hours), per kWh	$0.6613	$0.7036	$0.7486	$0.7965	$0.8475
Electric Cost Adjustment (ECA):					
On-Peak, per kWh	Sheet No. 2.17				
Off-Peak, per kWh	Sheet No. 2.17				
Off-Peak Saver, per kWh	Sheet No. 2.17				
Electric Capacity Charge (ECC), per kWh	Sheet No. 2.18				
Fixed Seasonal Option (ETR-F)					
Access and Facilities Charge, per day	$0.7316	$0.7784	$0.8282	$0.8812	$0.9376
Access and Facilities Charge:					
Winter (October – May), per kWh	$0.0763	$0.0812	$0.0864	$0.0919	$0.0978
Summer (June – September), per kWh	$0.1007	$0.1071	$0.1140	$0.1213	$0.1291
Electric Cost Adjustment (ECA), per kWh	Sheet No. 2.17				
Electric Capacity Charge (ECC), per kWh	Sheet No. 2.18				
Energy-Wise Net Metering Option (ERNM)	Sheet No. 2.20				
Frozen Commercial Service – Small (E1C) – Sheet No. 5					
Access and Facilities Charge, per day	$0.6421	$0.6832	$0.7269	$0.7734	$0.8229
Access and Facilities Charge, per kWh	$0.0876	$0.0932	$0.0992	$0.1055	$0.1123
Electric Cost Adjustment (ECA), per kWh	Sheet No. 2.17				
Electric Capacity Charge (ECC), per kWh	Sheet No. 2.18				
Commercial Service – Non-Metered (ENM) – Sheet No. 5.1					
Access and Facilities Charge, per kWh	$0.1172	$0.1295	$0.1431	$0.1581	$0.1747
Electric Cost Adjustment (ECA), per kWh	Sheet No. 2.17				
Electric Capacity Charge (ECC), per kWh	Sheet No. 2.18				

Note: 2025 rates are effective October 1, 2025. All other rates are effective January 1st of the respective year shown. Rates effective 2029 will remain effective until superseded by City Council.

ELECTRIC RATE SCHEDULES

RATE TABLE

Description	Rates (Note)				
	2025	2026	2027	2028	2029
Off-Peak Saver, per kWh	Sheet No. 2.17				
Electric Capacity Charge (ECC), per kWh	Sheet No. 2.18				
Fixed Seasonal Option (ECS-F)					
Access and Facilities Charge, per day	$0.7549	$0.8032	$0.8546	$0.9093	$0.9675
Access and Facilities Charge:					
Winter (October – May), per kWh	$0.0739	$0.0786	$0.0836	$0.0890	$0.0947
Summer (June – September), per kWh	$0.0782	$0.0832	$0.0885	$0.0942	$0.1002
Electric Cost Adjustment (ECA):	Sheet No. 2.17				
Electric Capacity Charge (ECC), per kWh	Sheet No. 2.18				
Energy-Wise Net Metering Option (ECSNM)	Sheet No. 2.20				
Frozen Commercial Service – General (E2C, ETC) – Sheet No. 6					
Frozen Standard Option (E2C)					
Access and Facilities Charge, per day	$1.0500	$1.1130	$1.1798	$1.2506	$1.3256
Access and Facilities Charge, per kWh	$0.0748	$0.0793	$0.0840	$0.0891	$0.0944
Electric Cost Adjustment (ECA):	Sheet No. 2.17				
Electric Capacity Charge (ECC), per kWh	Sheet No. 2.18				
Frozen Time-of-Day Option (ETC)					
Access and Facilities Charge, per day	$1.0500	$1.1130	$1.1798	$1.2506	$1.3256
Access and Facilities Charge:					
On-Peak, per kWh	$0.1384	$0.1467	$0.1555	$0.1648	$0.1747
Off-Peak, per kWh	$0.0554	$0.0587	$0.0622	$0.0660	$0.0699
Electric Cost Adjustment (ECA):					
On-Peak, per kWh	Sheet No. 2.17				
Off-Peak, per kWh	Sheet No. 2.17				
Electric Capacity Charge (ECC), per kWh	Sheet No. 2.18				

Note: 2025 rates are effective October 1, 2025. All other rates are effective January 1st of the respective year shown. Rates effective 2029 will remain effective until superseded by City Council.

ELECTRIC RATE SCHEDULES

RATE TABLE

Description	Rates (Note)				
	2025	2026	2027	2028	2029
Summer (June – September) Off-Peak, per kWh	$0.0497	$0.0527	$0.0559	$0.0593	$0.0629
Summer (June – September) Off-Peak Saver, per kWh	$0.0363	$0.0385	$0.0408	$0.0432	$0.0458
Critical Peak Period (During Event Hours), per kWh	$0.6781	$0.7188	$0.7619	$0.8076	$0.8561
Electric Cost Adjustment (ECA):					
On-Peak, per kWh	Sheet No. 2.17				
Off-Peak, per kWh	Sheet No. 2.17				
Off-Peak Saver, per kWh	Sheet No. 2.17				
Electric Capacity Charge (ECC), per kWh	Sheet No. 2.18				
Energy-Wise Net Metering Option (ECMNM)	Sheet No. 2.20				
Commercial Service – Large 50 kW Minimum (ECL, ECL-P)– Sheet No. 6.2					
Energy-Wise Standard Time-of-Day Option (ECL)					
Access and Facilities Charge, per day	$1.4598	$1.5474	$1.6402	$1.7386	$1.8429
Demand Charge Secondary:					
Winter (October – May), per kW, per day	$0.0172	$0.0182	$0.0193	$0.0205	$0.0217
Summer (June – September), per kW, per day	$0.0480	$0.0509	$0.0540	$0.0572	$0.0606
Access and Facilities Charge:					
Winter (October – May) On-Peak, per kWh	$0.0839	$0.0889	$0.0942	$0.0999	$0.1059
Winter (October – May) Off-Peak, per kWh	$0.0595	$0.0631	$0.0669	$0.0709	$0.0752
Summer (June – September) On-Peak, per kWh	$0.0993	$0.1053	$0.1116	$0.1183	$0.1254
Summer (June – September) Off-Peak, per kWh	$0.0595	$0.0631	$0.0669	$0.0709	$0.0752
Electric Cost Adjustment (ECA):					
On-Peak, per kWh	Sheet No. 2.17				
Off-Peak, per kWh	Sheet No. 2.17				
Electric Capacity Charge (ECC), per kWh	Sheet No. 2.18				
Energy-Wise Plus Time-of-Day Option (ECL-P)					
Access and Facilities Charge, per day	$1.4598	$1.5474	$1.6402	$1.7386	$1.8429

Note: 2025 rates are effective October 1, 2025. All other rates are effective January 1st of the respective year shown. Rates effective 2029 will remain effective until superseded by City Council.

ELECTRIC RATE SCHEDULES

RATE TABLE

Description	Rates (Note)				
	2025	2026	2027	2028	2029
Demand Charge Secondary:					
Winter (October – May), per kW, per day	$0.0756	$0.0801	$0.0849	$0.0900	$0.0954
Summer (June – September), per kW, per day	$0.0937	$0.0993	$0.1053	$0.1116	$0.1183
Access and Facilities Charge:					
Winter (October – May) On-Peak, per kWh	$0.0564	$0.0598	$0.0634	$0.0672	$0.0712
Winter (October – May) Off-Peak, per kWh	$0.0443	$0.0470	$0.0498	$0.0528	$0.0560
Winter (October – May) Off-Peak Saver, per kWh	$0.0266	$0.0282	$0.0299	$0.0317	$0.0336
Summer (June – September) On-Peak, per kWh	$0.1707	$0.1809	$0.1918	$0.2033	$0.2155
Summer (June – September) Off-Peak, per kWh	$0.0443	$0.0470	$0.0498	$0.0528	$0.0560
Summer (June – September) Off-Peak Saver, per kWh	$0.0306	$0.0324	$0.0343	$0.0364	$0.0386
Critical Peak Period (During Event Hours), per kWh	$0.5878	$0.6231	$0.6605	$0.7001	$0.7421
Electric Cost Adjustment (ECA):					
On-Peak, per kWh	Sheet No. 2.17				
Off-Peak, per kWh	Sheet No. 2.17				
Off-Peak Saver, per kWh	Sheet No. 2.17				
Electric Capacity Charge (ECC), per kWh	Sheet No. 2.18				
Energy-Wise Net Metering Option (ECLNM)	Sheet No. 2.20				
Frozen Industrial Service – 1,000 kWh/Day Minimum (ETL, ETLO, ETLW) – Sheet No. 7					
Frozen Standard Option (ETL)					
Access and Facilities Charge, per day	$3.5132	$3.7187	$3.9363	$4.1665	$4.4103
Demand Charge Secondary:					
On-Peak, per kW, per day	$0.8459	$0.8954	$0.9478	$1.0032	$1.0619
Off-Peak, per kW, per day	$0.5498	$0.5820	$0.6160	$0.6520	$0.6902
Electric Cost Adjustment (ECA):					
On-Peak, per kWh	Sheet No. 2.17				
Off-Peak, per kWh	Sheet No. 2.17				

Note: 2025 rates are effective October 1, 2025. All other rates are effective January 1st of the respective year shown. Rates effective 2029 will remain effective until superseded by City Council.

ELECTRIC RATE SCHEDULES

RATE TABLE

Description	Rates (Note)		
	2027	2028	2029
Net Metering – Sheet No. 20			
Residential Service Energy-Wise Net Metering Option (ERNM) – Sheet No. 4			
Access and Facilities Charge, per day	$0.8265	$0.8802	$0.9374
Access and Facilities Charge, per kWh	$0.0294	$0.0313	$0.0333
Demand Charge Secondary, per kW, per day	$0.4329	$0.4610	$0.4910
Electric Cost Adjustment (ECA), per kWh	$0.0263		
Electric Capacity Charge (ECC), per kWh	$0.0066		
Commercial Service – Small Energy-Wise Net Metering Option (ECSNM) – Sheet No. 5.2			
Access and Facilities Charge, per day	$0.8265	$0.8802	$0.9374
Access and Facilities Charge, per kWh	$0.0294	$0.0313	$0.0333
Demand Charge Secondary, per kW, per day	$0.3456	$0.3681	$0.3920
Electric Cost Adjustment (ECA), per kWh	$0.0263		
Electric Capacity Charge (ECC), per kWh	$0.0066		
Commercial Service – Medium Energy-Wise Net Metering Option (ECMNM) – Sheet No. 6.1			
Access and Facilities Charge, per day	$1.1759	$1.2523	$1.3337
Access and Facilities Charge, per kWh	$0.0505	$0.0538	$0.0573
Demand Charge Secondary, per kW, per day	$0.4662	$0.4965	$0.5288
Electric Cost Adjustment (ECA), per kWh	$0.0263		
Electric Capacity Charge (ECC), per kWh	$0.0056		
Commercial Service – Large Energy-Wise Net Metering Option (ECLNM) – Sheet No. 6.2			
Access and Facilities Charge, per day	$1.5253	$1.6244	$1.7300
Access and Facilities Charge, per kWh	$0.0470	$0.0501	$0.0534
Demand Charge Secondary, per kW, per day	$0.4662	$0.4965	$0.5288
Electric Cost Adjustment (ECA), per kWh	$0.0263		
Electric Capacity Charge (ECC), per kWh	$0.0056		
All Other Rate Schedules billed under applicable Energy-Wise standard or frozen option.			

Note: All rates are effective January 1st of the respective year shown. Rates effective 2029 will remain effective until superseded by City Council.

ELECTRIC RATE SCHEDULES

GENERAL

DEMAND DETERMINATIONS

Commercial Service (ECM, ECM-P, ECL, ECL-P)

Maximum Demand and/or Billing Demand:

Greatest 15-minute load during any block of time in the billing period.

Residential and Commercial Energy-Wise Net Metering (ERNM, ECSNM, ECMNM, ECLNM):

Greatest 15-minute net load during any On-Peak Period in the billing period.

Industrial and Contract Service

Maximum Demand (ETL, EIS, EIS-P, E8T, E8T-P, E8S, E8S-P, ELG, ELG-P, ETX, ECD, ECD-P, ELL)

Maximum Demand is the greatest 15-minute load during any time in the billing period adjusted upward by 1% for each 1% that the power factor of Customer is below 95% lagging or leading.

Billing Demand

Energy-Wise Standard Time-of-Day Option (ETL, EIS, E8T, E8S, ELG, ETX, ECD)

On-Peak:

The greatest 15-minute load during On-Peak hours in the billing period adjusted upward by 1% for each 1% that the power factor of Customer is below 95% lagging or leading.

Off-Peak: either A or B, whichever is greater.

A. The greatest 15-minute load during Off-Peak hours in the billing period adjusted upward by 1% for each 1% that the power factor of Customer is below 95% lagging or leading, minus the
On-Peak Billing Demand. Such demand will not be less than zero.

B. 68% of the Maximum Demand during the last 12 billing periods, minus the On-Peak Billing Demand. Such demand will not be less than zero. Part B of Off-Peak Billing Demand is not applicable to Industrial Service – Transmission Voltage (ETX).

Energy-Wise Plus Time-of-Day Peak Option (EIS-P, E8T-P, E8S-P, ELG-P, ECD-P)

Demand:

The greatest 15-minute load during any time in the billing period adjusted upward by 1% for each 1% that the power factor of Customer is below 95% lagging or leading.

Industrial Service – Large Load (ELL) see Sheet No. 27.1

ENERGY-WISE, ENERGY-WISE PLUS, AND FIXED SEASONAL TRANSITION TERMS AND CONDITIONS

Residential Service

Unless Utilities, at its sole discretion, determines temporarily establishing service under the Frozen Option (E1R) is in best interest of Utilities, Customers establishing service after September 30, 2025, will initially receive service under the Energy-Wise Standard Time-of-Day Option (ETR) unless request is made to receive service under the alternate Energy-Wise Plus Time-of-Day (ETR-P) or the Fixed Seasonal (ETR-F) options. With the exception for Customers receiving service under the Net Metering Rate Schedule (which are addressed below), Customers with standard meters receiving service under the Frozen Option (E1R) will be transitioned to service under the Energy-Wise Standard Time-of-Day Option (ETR) according to a schedule determined by Utilities. If eligible, Customers with standard meters receiving service under the Frozen Option (E1R) may request to receive service under the Energy-Wise Standard Time-of-Day (ETR), the Energy-Wise Plus Time-of-Day Option (ETR-P), or the Fixed Seasonal Option (ETR-F). However, Utilities, at its sole discretion, may decline such requests based on Utilities' transition schedule or other operational considerations. Customers receiving service under the Frozen Option (E1R) who have chosen to receive a nonstandard meter under Utilities' Automated-Meter Opt-Out Program will be transitioned to the Fixed Seasonal Option (ETR-F). Customers receiving service under the Net Metering Rate Schedule will be transitioned to service under the Energy-Wise Net Metering Option (ERNM) on January 1, 2027.

Commercial and Industrial Service

Service under Frozen Rate Schedules (E1C, E2C, ETC, ETL, ETLO, ETLW) is frozen to new participation, except in instances when Customers on frozen rate schedules are switched to the appropriate frozen rate schedule under Utilities' Dynamic Rate Switching. Unless Utilities, at its sole discretion, determines temporarily establishing service under Frozen Rate Schedules (E1C, E2C, ETL) is in the best interest of Utilities, Customers establishing service after September 30, 2025, will initially receive service under the appropriate Commercial Service – Small (ECS, ECS-P, ECS-F), Commercial Service – Medium 10 kW Minimum (ECM, ECM-P), Commercial Service – Large 50 kW Minimum (ECL, ECL-P), Industrial Service – 100 kW Minimum (EIS, EIS-P), Industrial Service – 500 kW Minimum (E8T, E8T-P), or Industrial Service – 4,000 kW Minimum (E8S, E8S-P) Rate Schedule. With the exception of customers receiving service under the Net Metering Rate Schedule, Customers receiving service under Frozen Rate Schedules (E1C, E2C, ETC, ETL, ETLO, ETLW) will be transitioned to the applicable Commercial Service – Small (ECS),

ELECTRIC RATE SCHEDULES

GENERAL

Commercial Service – Medium 10 kW Minimum (ECM), Commercial Service – Large 50 kW Minimum (ECL), Industrial Service – 100 kW Minimum (EIS), Industrial Service – 500 kW Minimum (E8T), or Industrial Service – 4,000 kW Minimum (E8S) Energy-Wise Standard Time-of-Day Option according to a schedule determined by Utilities. If eligible, Customers receiving service under Frozen Rate Schedules (E1C, E2C, ETC, ETL, ETLO, ETLW) may request to receive service under the applicable Commercial Service – Small (ECS, ECS-P, ECS-F), Commercial Service – Medium 10 kW Minimum (ECM, ECM-P), Commercial Service – Large 50 kW Minimum (ECL, ECL-P), Industrial Service – 100 kW Minimum (EIS, EIS-P), Industrial Service – 500 kW Minimum (E8T, E8T-P), or Industrial Service – 4,000 kW Minimum (E8S, E8S-P) Rate Schedule. However, Utilities at its sole discretion may decline such requests based on Utilities' transition schedule or other operational considerations.

Customers receiving service under Commercial Service – Small (ECS, ECS-P), Commercial Service – Medium 10 kW Minimum (ECM, ECM-P), Commercial Service – Large 50 kW Minimum (ECL, ECL-P), Industrial Service – 100 kW Minimum (EIS, EIS-P), Industrial Service – 500 kW Minimum (E8T, E8T-P), or Industrial Service – 4,000 kW Minimum (E8S, E8S-P) Rate Schedule will be switched to the appropriate rate schedule under Utilities' Dynamic Rate Switching. Commercial Customers receiving service under the Net Metering Rate Schedule will be transitioned to service under the applicable Energy-Wise Net Metering Option (ECSNM, ECMNM, ECLNM) on January 1, 2027.

ELECTRIC RATE SCHEDULES

RESIDENTIAL SERVICE (E1R, ETR, ETR-P, ETR-F, ERNM)

AVAILABILITY

As provided in the Energy-Wise, Energy-Wise Plus, and Fixed Seasonal Transition Terms and Conditions of these Electric Rate Schedules, service under this rate schedule is available in Utilities' electric service territory for general residential purposes. Whether or not the end use of the electric service is residential in nature, this rate is not available for master metered or nonresidential accounts.

RATE OPTIONS

Customers may choose between the following:

A. Frozen Option (E1R)
Unless Utilities determines temporarily establishing service under this option is in the best interest of Utilities, service under this option is frozen to new participation.

B. Energy-Wise Standard Time-of-Day Option (ETR)
Service under this option is not available to Customers choosing to receive a nonstandard meter under Utilities' Automated-Meter Opt-Out Program. Service under this option is not available to customers receiving service under the Net Metering Rate Schedule.

C. Energy-Wise Plus Time-of-Day Option (ETR-P)
Service under this option is not available to Customers who: (a) choose to receive a nonstandard meter under Utilities Automated-Meter Opt-Out Program; b) receive service under the Net Metering Rate Schedule; c) receive service under the Community Solar Garden Bill Credit (Pilot Program) or Community Solar Garden Program Rate Schedules.

D. Fixed Seasonal Option (ETR-F)
Customers choosing to receive a nonstandard meter under Utilities' Automated-Meter Opt-Out Program are required to receive service under this option. Service under this option is not available to customers receiving service under the Net Metering Rate Schedule.

E. Energy-Wise Net Metering Option (ERNM)
Service under this option is available to customers receiving service under the Net Metering Rate Schedule.

RATE

See Rate Table for applicable charges.

ELECTRIC RATE SCHEDULES

FROZEN COMMERCIAL SERVICE – SMALL (E1C)

AVAILABILITY

As provided in the Energy-Wise, Energy-Wise Plus, and Fixed Seasonal Transition Terms and Conditions of these Electric Rate Schedules, service under this rate schedule is available in Utilities' electric service territory for any establishment engaged in the operation of a business or an institution, whether or not for profit, whose average daily usage (billing period kWh divided by the number of days in the billing period) does not exceed 33 kWh in any of the last 12 billing periods. Unless Utilities determines temporarily establishing service under this option is in the best interest of Utilities, service under this option is frozen to new participation.

RATE

See Rate Table for applicable charges.

ELECTRIC RATE SCHEDULES

COMMERCIAL SERVICE – SMALL (ECS, ECS-P, ECS-F, ECSNM)

AVAILABILITY

As provided in the Energy-Wise, Energy-Wise Plus, and Fixed Seasonal Transition Terms and Conditions of these Electric Rate Schedules, service under this rate schedule is available in Utilities' electric service territory for any establishment engaged in the operation of a business or an institution, whether or not for profit, whose Maximum Demand is less than 10 kW in each of the last 12 billing periods.

RATE OPTIONS

Customers may choose between the following:

A. Energy-Wise Standard Time-of-Day Option (ECS)
Service under this option is not available to Customers who receive service under the Net Metering Rate Schedule.

B. Energy-Wise Plus Time-of-Day Option (ECS-P)
Service under this option is not available to Customers who: (a) receive service under the Net Metering Rate Schedule; (b) receive service under the Community Solar Garden Bill Credit (Pilot Program) Rate Schedule, or (c) receive service under the Community Solar Garden Program Rate Schedule.

C. Fixed Seasonal Option (ECS-F)
Service under this option is not available to customers receiving service under the Net Metering Rate Schedule.

D. Energy-Wise Net Metering Option (ECSNM)
Service under this option is available to customers receiving service under the Net Metering Rate Schedule.

RATE

See Rate Table for applicable charges.

ELECTRIC RATE SCHEDULES
FROZEN COMMERCIAL SERVICE – GENERAL (E2C, ETC)

AVAILABILITY

As provided in the Energy-Wise, Energy-Wise Plus, and Fixed Seasonal Transition Terms and Conditions of these Electric Rate Schedules, service under this rate schedule is available in Utilities' electric service territory for any establishment engaged in the operation of a business or an institution, whether or not for profit, whose average daily usage (billing period kWh divided by the number of days in the billing period) is greater than 33 kWh in any of the last 12 billing periods. This rate schedule is not available to Customers whose average daily usage equals or exceeds 1,000 kWh in any of the last 12 billing periods. Unless Utilities determines temporarily establishing service under this option is in the best interest of Utilities, service under this option is frozen to new participation.

RATE OPTIONS

Customers may choose between the following:

A. Frozen Standard Option (E2C)

B. Frozen Time-of-Day Option (ETC)

RATE

See Rate Table for applicable charges.

ELECTRIC RATE SCHEDULES

COMMERCIAL SERVICE – MEDIUM 10 kW MINIMUM (ECM, ECM-P, ECMNM)

AVAILABILITY

As provided in the Energy-Wise, Energy-Wise Plus, and Fixed Seasonal Transition Terms and Conditions of these Electric Rate Schedules, service under this rate schedule is available in Utilities' electric service territory for any establishment engaged in the operation of a business or an institution, whether or not for profit, whose Maximum Demand equals or exceeds 10 kW in any of the last 12 billing periods. This rate schedule is not available to Customers whose Maximum Demand equals or exceeds 50 kW in any of the last 12 billing periods.

RATE OPTIONS

Customers may choose between the following:

A. Energy-Wise Standard Time-of-Day Option (ECM)
   Service under this option is not available to Customers who receive service under the Net Metering Rate Schedule.

B. Energy-Wise Plus Time-of-Day Option (ECM-P)
   Service under this option is not available to Customers who: (a) receive service under the Net Metering Rate Schedule; (b) receive service under the Community Solar Garden Bill Credit (Pilot Program) Rate Schedule, or (c) receive service under the Community Solar Garden Program Rate Schedule.

C. Energy-Wise Net Metering Option (ECMNM)
   Service under this option is available to customers receiving service under the Net Metering Rate Schedule.

RATE

See Rate Table for applicable charges.

ELECTRIC RATE SCHEDULES

COMMERCIAL SERVICE – LARGE 50 kW MINIMUM (ECL, ECL-P, ECLNM)

AVAILABILITY

As provided in the Energy-Wise, Energy-Wise Plus, and Fixed Seasonal Transition Terms and Conditions of these Electric Rate Schedules, service under this rate schedule is available in Utilities' electric service territory for any establishment engaged in the operation of a business or an institution, whether or not for profit, whose Maximum Demand equals or exceeds 50 kW in any of the last 12 billing periods. This rate schedule is not available to Customers whose Maximum Demand equals or exceeds 100 kW in any of the last 12 billing periods.

RATE OPTIONS

Customers may choose between the following:

A. Energy-Wise Standard Time-of-Day Option (ECL)
Service under this option is not available to Customers who receive service under the Net Metering Rate Schedule.

B. Energy-Wise Plus Time-of-Day Option (ECL-P)
Service under this option is not available to Customers who: (a) receive service under the Net Metering Rate Schedule; (b) receive service under the Community Solar Garden Bill Credit (Pilot Program) Rate Schedule, or (c) receive service under the Community Solar Garden Program Rate Schedule.

C. Energy-Wise Net Metering Option (ECLNM)
Service under this option is available to customers receiving service under the Net Metering Rate Schedule.

RATE

See Rate Table for applicable charges.

ELECTRIC RATE SCHEDULES

FROZEN INDUSTRIAL SERVICE – 1,000 kWh/DAY MINIMUM (ETL, ETLO, ETLW)

AVAILABILITY

As provided in the Energy-Wise, Energy-Wise Plus, and Fixed Seasonal Transition Terms and Conditions of these Electric Rate Schedules, service under this rate schedule is available in Utilities' electric service territory for Customers whose average daily usage (billing period kWh divided by the number of days in the billing period) equals or exceeds 1,000 kWh in any 12-month billing period. This rate is not available to Customers whose Maximum Demand equals or exceeds 500 kW in any of the last 12 billing periods. Unless Utilities determines temporarily establishing service under this option is in the best interest of Utilities, service under this option is frozen to new participation.

RATE OPTIONS

Customers may choose between the following:

A. Frozen Standard Option (ETL)

B. Frozen Non-Demand Summer Option (ETLO)
   Available under separate contract, Customers may elect Non-Demand Summer Option. Customers electing this option must consume 75% or more of their 12 billing periods kWh during the Summer period (May through October).

C. Frozen Non-Demand Winter Option (ETLW)
   Available under separate contract, Customers may elect Non-Demand Winter Option. Customers electing this option must consume 75% or more of their annual calendar year kWh during the Winter period (November through April).

RATE

See Rate Table for applicable charges.

ELECTRIC RATE SCHEDULES
INDUSTRIAL SERVICE – 100 kW MINIMUM (EIS EIS-P)

AVAILABILITY

As provided in the Energy-Wise, Energy-Wise Plus, and Fixed Seasonal Transition Terms and Conditions of these Electric Rate Schedules, service under this rate schedule is available in Utilities' electric service territory for Customers whose Maximum Demand equals or exceeds 100 kW in any of the last 12 billing periods. Service is not available under this rate schedule for any Customer whose Maximum Demand equals or exceeds 500 kW in any of the last 12 billing periods.

RATE OPTIONS

Customers may choose between the following:

A. Energy-Wise Standard Time-of-Day Option (EIS)
Service under this option is not available to Customers who receive service under the Net Metering Rate Schedule.

B. Energy-Wise Plus Time-of-Day Option (EIS-P)
Service under this option is not available to Customers who: (a) receive service under the Net Metering Rate Schedule; (b) receive service under the Community Solar Garden Bill Credit (Pilot Program) Rate Schedule, or (c) receive service under the Community Solar Garden Program Rate Schedule.

RATE

See Rate Table for applicable charges.

ELECTRIC RATE SCHEDULES
INDUSTRIAL SERVICE – 500 kW MINIMUM (E8T, E8T-P)

AVAILABILITY

As provided in the Energy-Wise, Energy-Wise Plus, and Fixed Seasonal Transition Terms and Conditions of these Electric Rate Schedules, service under this rate schedule is available in Utilities' electric service territory for Customers whose Maximum Demand equals or exceeds 500 kW in any of the last 12 billing periods. Service is not available under this rate schedule for any Customer whose Maximum Demand equals or exceeds 4,000 kW in any of the last 12 billing periods.

RATE OPTIONS

Customers may choose between the following:

A. Energy-Wise Standard Time-of-Day Option (E8T)

B. Energy-Wise Plus Time-of-Day Option (E8T-P)
Service under this option is not available to Customers who: (a) receive service under the Net Metering Rate Schedule; (b) receive service under the Community Solar Garden Bill Credit (Pilot Program) Rate Schedule, or (c) receive service under the Community Solar Garden Program Rate Schedule.

RATE

See Rate Table for applicable charges.

ELECTRIC RATE SCHEDULES
INDUSTRIAL SERVICE – 4,000 kW MINIMUM (E8S, E8S-P)

AVAILABILITY

As provided in the Energy-Wise, Energy-Wise Plus, and Fixed Seasonal Transition Terms and Conditions of these Electric Rate Schedules, service under this rate schedule is available in Utilities' electric service territory for Customers whose Maximum Demand equals or exceeds 4,000 kW in any of the last 12 billing periods. Service is not available under this rate schedule for any Customer whose Maximum Demand equals or exceeds 10,000 kW in any of the last 12 billing periods or whose Maximum Demand is reasonably expected to equal or exceed 10,000 kW in any billing period in the next 120 billing periods.

RATE OPTIONS

Customers may choose between the following:

A. Energy-Wise Standard Time-of-Day Option (E8S)

B. Energy-Wise Plus Time-of-Day Option (E8S-P)
Service under this option is not available to Customers who: (a) receive service under the Net Metering Rate Schedule; (b) receive service under the Community Solar Garden Bill Credit (Pilot Program) Rate Schedule, or (c) receive service under the Community Solar Garden Program Rate Schedule.

RATE

See Rate Table for applicable charges.

ELECTRIC RATE SCHEDULES

INDUSTRIAL SERVICE – LARGE POWER AND LIGHT (ELG, ELG-P)

AVAILABILITY

Available by contract in Utilities' electric service territory for the Customers whose aggregated Maximum Demand equals or exceeds 4,000 kW in any of the last 12 billing periods. Service is not available under this rate schedule for any Customer whose Maximum Demand equals or exceeds 10,000 kW in any of the last 12 billing periods or whose Maximum Demand is reasonably expected to equal or exceed 10,000 kW in any billing period in the next 120 billing periods. Demand aggregation may only be performed for contiguous service properties on a Customer campus setting. Customers must maintain an annual load factor of 75% or greater.

Annual load factor is derived by multiplying the annual kWh in the period by 100 and dividing by the product of the maximum real demand (prior to power factor correction) in kW and the number of hours in the period. Annual reviews will be conducted by Utilities at the end of the Customer's annual contract period. Annual kWh will be adjusted for Customers receiving service under the Interruptible Service Rate Schedule.

Customers who select this service will be required to provide a suitable location for the aggregation equipment. Totalization charges do not apply to this offering.

RATE OPTIONS

Customers may choose between the following:

A. Energy-Wise Standard Option (ELG)

B. Energy-Wise Plus Time-of-Day Option (ELG-P)
   Service under this option is not available to Customers who: (a) receive service under the Net Metering Rate Schedule; (b) receive service under the Community Solar Garden Bill Credit (Pilot Program) Rate Schedule, or (c) receive service under the Community Solar Garden Program Rate Schedule.

RATE

See Rate Table for applicable charges.

ELECTRIC RATE SCHEDULES
CONTRACT SERVICE – MILITARY (ECD, ECD-P, EHYDPWR, EINFPRS)

AVAILABILITY

Available by contract in Utilities' electric service territory to the United States of America at the Fort Carson Military Installation, the Peterson Space Force Base, the United States Air Force Academy, and the Cheyenne Mountain Space Force Station.

RATE OPTIONS

Customers may choose between the following:

A. Energy-Wise Standard Time-of-Day Option (ECD)

B. Energy-Wise Plus Time-of-Day Option (ECD-P)
Service under this option is not available to Customers who: (a) receive service under the Net Metering Rate Schedule; (b) receive service under the Community Solar Garden Bill Credit (Pilot Program) Rate Schedule, or (c) receive service under the Community Solar Garden Program Rate Schedule.

RATE

See Rate Table for applicable charges.

ADDITIONAL SERVICES

In addition to the standard Contract Service to the listed military installations:

A. Military Hydroelectric Power Sales Service (EHYDPWR) is available by contract to the United States of America at the Fort Carson Military Installation for sales of electric energy for transmission over Utilities' electric system for final consumption within the geographic confines of the Fort Carson Military Installation.

B. On-site, Direct-service Solar Contract Service – USAFA (EINFPRS) is available by contract to the United States of America at the United States Air Force Academy for solar energy electric service provided from solar electric generating facilities located within the geographic confines of the United States Air Force Academy and with direct electric service from those solar electric generating facilities provided to the United States Air Force Academy.

ELECTRIC RATE SCHEDULES
NET METERING

AVAILABILITY

Available by contract in Utilities' service territory to Customers whose electric service is supplied by Utilities under any rate schedule, except as otherwise provided in these Electric Rate Schedules.

APPLICABILITY

Service under this rate schedule will be provided to Customers that either:

A. install an eligible Renewable Energy System and execute a Utilities' Interconnection Agreement (Agreement) to participate in the Net Metering Program (Program), or

B. lease an eligible Renewable Energy System located at their residence or business and elect to participate in the Program, and the owner of the eligible Renewable Energy System executes an Agreement.

The Program is available to Customers who either: a) own, operate, and maintain in parallel with Utilities' electric system an eligible Renewable Energy System, or b) lease an eligible Renewable Energy System and the owner of that system operates and maintains the system in parallel with Utilities' electric system.

The eligible Renewable Energy System, as defined in Section 40-2-124, C.R.S., may not be sized larger than 120% of the Customer's annual kilowatt-hour usage, actual or, at Utilities' discretion estimated. The photovoltaic generation system or other approved eligible Renewable Energy System will be limited to a maximum design capacity of 15 kW alternating current (AC) for Residential Customers and 150 kW AC for Commercial and Industrial Customers. Systems with a design capacity in excess of 150 kW AC for Commercial and Industrial Customers may be considered and are subject to approval by Utilities.

NET METERING

Net Metering is, for billing purposes, the net consumption as measured at Utilities' service meter, such that the renewable energy production need not be separately measured by the service meter other than for informational purposes. In the event that net metering is negative such that the eligible Renewable Energy System production is greater than the Customer's consumption in any month, Utilities will allow excess generation credits (kilowatt-hours) to be carried over and applied to the following month(s).

Any excess generation credits accrued will be credited to the Customer's account annually at the Small Power Producers and Cogeneration Service Rate Schedule. Customers receiving service under a rate schedule subject to the Fixed ECA will have credits calculated at the Small Power Producers and Cogeneration Service Rate Schedule as follows: 14% of the On-Peak Rate plus 86% of the Off-Peak Rate. Customers will be billed the applicable per day Access and Facilities Charges each month regardless of excess generation during that month.

RATE

See Rate Table.

The Customer may make a one-time election, in writing, on or before the end of a calendar year, to request that the excess kilowatt-hours be carried forward as a credit from month-to-month indefinitely until the Customer terminates service with Utilities, at which time no payment shall be required from Utilities for any remaining excess kilowatt hour credits supplied by the Customer.

All electric power and energy delivered by Utilities to the Customer under this rate schedule will be received and paid for by the Customer at the applicable Residential, Commercial or Industrial Service Rate Schedule. All applicable Access and Facilities charges, ECA and ECC will apply.

RENEWABLE ENERGY CREDITS

Renewable Energy Credits as referenced in Section 40-2-124.1(d), C.R.S., are the environmental attributes of renewable energy generation. A Renewable Energy Credit represents one MWh of renewable energy that is physically metered and verified. If a rebate or an incentive payment has been made by Utilities to the Customer, then Utilities shall own all Renewable Energy Credits or other environmental attributes generated under this tariff as provided for in the policies, rules, and agreement related to the rebate or incentive program and that are accepted by the Customer.

ELECTRIC RATE SCHEDULES

COMMUNITY SOLAR GARDEN PROGRAM

AVAILABILITY

The Community Solar Garden Program (Program) is available under the terms and conditions of this rate schedule to all Customers taking service under Utilities' Electric Rate Schedules with the following exceptions: (a) Energy-Wise Plus Time-of-Day Peak Options (ETR-P, ECS-P, ECM-P, ECL-P, EIS-P, E8T-P, E8S-P, ELG-P, ECD-P), (b) Commercial Service – Non-Metered (ENM), (c) Contract Service – Military Wheeling (ECW), (d) Contract Service – Traffic Signals (E2T), (e) Contract Service – Street Lighting (E7SL), (f) Electric Cost Adjustment (ECA), (g) Electric Capacity Charge (ECC), (h) Totalization Service, (i) Enhanced Power Service, (j) Net Metering, (k) Small Power Producers & Cogeneration Service, and (l) Community Solar Garden Bill Credit (Pilot Program). All Customers that participate under this rate schedule must hold evidence of ownership to, a subscription as evidence of beneficial use of, or an entitlement to the electric generating capacity of a Community Solar Garden Facility (Customer Solar Garden Interest). Customers may choose any Community Solar Garden Facility that conforms to this rate schedule.

The choice of a Community Solar Garden Facility and the purchase of a Customer Solar Garden Interest is solely the responsibility of the Customer and are undertaken at the Customer's risk. Utilities makes no representations or warranties concerning the Community Solar Garden Facility and its operation and maintenance and its financial viability or the continued usefulness of any Customer Solar Garden Interest.

COMMUNITY SOLAR GARDEN FACILITY

A Community Solar Garden Facility for purposes of this rate schedule is a photovoltaic electric generating installation having a nameplate rating of not less than 0.5 megawatts Alternating Current (MWAC) and not more than 2.0 MWAC in electric generating capacity and the owning entity that has executed an Interconnection Agreement with Utilities. If the Interconnection Agreement is extended, Utilities will retain the Renewable Energy Credits through the extension period at no additional cost. The physical location of any Community Solar Garden Facility under this rate schedule shall be within the electric service territory of Utilities and any electric power produced by the Community Solar Garden Facility shall be consumed within the electric service territory of Utilities. All costs of interconnection for the Community Solar Garden Facility shall be borne and paid by the legal owner of the Community Solar Garden Facility.

This Program will allow for up to 2.0 MWAC of electric generating capacity to be added to Utilities' portfolio of Distributed Generation resources.

Electric

Worksheets

Electric Contract Service –

Military Wheeling (ECW)

Worksheets

Colorado Springs Utilities
2026 Electric Contract Service - Military Wheeling (ECW) Worksheet

WORKSHEET 1 - SUMMARY OF CURRENT AND PROPOSED ECW RATES

Line No.	Rate Class	Current Rate	Calculated Rate	Proposed Increase / (Decrease)	Percent Rate Change	2026-2029 Proposed Rates [1]	Proposed 2026	Proposed 2027	Proposed 2028	Proposed 2029
(a)	(b)	(c)	(d)	(e) (d) - (c)	(f) (e) / (c)	(g)	(h) (d) * [1 + (g)]	(i) (h) * [1 + (g)]	(j) (i) * [1 + (g)]	(k) (j) * [1 + (g)]
1	Demand Charge, per kW, per day	$ 0.0806	$ 0.1886	$ 0.1080	134.0%	**6.50%**	$ 0.2009	$ 0.2140	$ 0.2279	$ 0.2427

Note: [1] *The proposed rates for 2026, 2027, 2028, and 2029 are based on a 6.5% electric system annual increase in accordance with Council resolution 172-24 passed on 11/12/2024.*

Colorado Springs Utilities
2026 Electric Contract Service - Military Wheeling (ECW) Worksheet

WORKSHEET 1.1 - ECW RATE CALCULATION

Line No.	Rate Class	Amount
(a)	(b)	(c)
1	**ECW Demand Charge**	
2	ECW Net Revenue Requirement	$ 567,940
3	Number of Days	365
4	Forecasted Billing Demand (kW)	8,250
5	**ECW Demand Charge, per kW, per day**	**$ 0.1886**

Colorado Springs Utilities
2026 Electric Contract Service - Military Wheeling (ECW) Worksheet

WORKSHEET 1.2 - CURRENT AND PROPOSED ECW NET REVENUE REQUIREMENT [1]

				Distribution							
Line No.	Rate Class	Generation Non-Fuel	Trans-mission	Sub-station	Line - Primary	Line - Secondary	Electric Service, Meters and Installation	Street Lighting	Customer	Surplus Payments to the City [2]	Net Revenue Requirement
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Current ECW	$ -	$ -	$ 11,199	$ 48,355	$ 10,641	$ 469	$ -	$ 12,913	$ 159,351	$ 242,927
2	Proposed ECW	$ -	$ 302,653	$ 11,199	$ 48,355	$ 10,641	$ 469	$ -	$ 12,913	$ 181,710	$ 567,940

Notes:

[1] *Substation, Distribution, Street Lighting, Customer, and current Surplus Payments to City amounts sourced from 2025 Cost of Service Study, Schedule 7.*

[2] *The current ECW rate was reduced to avoid duplicated collection of Surplus Payments to City under both OATT and ECW. With Transmission cost now being recovered through ECW charges, the Surplus reduction is eliminated.*

Colorado Springs Utilities
2026 Electric Contract Service - Military Wheeling (ECW) Worksheet

WORKSHEET 1.3 - ALLOCATION OF TRANSMISSION COST

Line No.	Rate Class	Energy	Demand	Total
(a)	(b)	(c)	(d)	(e) (c) + (d)
1	Total Electric Transmission Cost	$ 19,599,822	$ 13,563,134	$ 33,162,956
2	ECW Allocation Percent	0.65%	1.29%	
3	Allocation Amount *(Line 1 * Line 2)*	$ 128,263	$ 174,390	$ 302,653

Note : Classsified Transmission cost sourced from the 2025 Electric Cost of Service Study Schedule 5.

Colorado Springs Utilities
2026 Electric Contract Service - Military Wheeling (ECW) Worksheet

WORKSHEET 1.4 - ENERGY AND DEMAND ALLOCATION FACTOR DETAIL

Line No.	Rate Class	Energy Sales (kWh)	Composite Loss Multiplier	Energy Output to Lines Excluding Wheeling (kWh)	NCP Demand (kW)	3CP (kW)	Average Demand (kW)	Excess Demand 3 CP (kW)
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	ECW	33,148,034	1.019040	33,779,178	538	8,250	3,856	4,394
2	Total Electric			5,161,764,117				341,737
3	Allocation Percent *(Line 1 / Line 2)*			0.65%				1.29%

Note : ECW energy sales, NCP, the composite loss multiplier, total Electric output to lines, and total Electric Excess Demand 3 CP sourced from the 2025 Electric Cost of Service Study Schedule 6.3. The ECW 3CP sourced from the forecasted billing determinant from Worksheet 1.5.

Colorado Springs Utilities
2026 Electric Contract Service - Military Wheeling (ECW) Worksheet

WORKSHEET 1.5 - FORECASTED BILLING UNITS

Line No.	Rate Class	Average Customers	Additional Meters	Energy Sales (kWh)	Billing Demand (kW)
(a)	(b)	(c)	(d)	(e)	(f)
1	ECW	4	-	33,148,034	8,250

Energy-Wise Net Metering

Rate Option Worksheets

Colorado Springs Utilities
2027 Energy-Wise Net Metering Rate Option
Effective January 1, 2027

WORKSHEET 1 - SUMMARY OF PROPOSED RATES

Line No.	Rate Class	Calculated Rate Derived from 2025 Rate Case	Proposed Rates 2027	Proposed Rates 2028	Proposed Rates 2029
(a)	(b)	(c)	(d)	(e)	(f)
1	**Residential (ERNM)**				
2	Access and Facilities Charge, per day	$ 0.7287	$ 0.8265	$ 0.8802	$ 0.9374
3	Access and Facilities Charge, per kWh	$ 0.0259	$ 0.0294	$ 0.0313	$ 0.0333
4	Demand Charge Secondary, per kW, per day	$ 0.3817	$ 0.4329	$ 0.4610	$ 0.4910
5	**Commercial - Small (ECSNM)**				
6	Access and Facilities Charge, per day	$ 0.7287	$ 0.8265	$ 0.8802	$ 0.9374
7	Access and Facilities Charge, per kWh	$ 0.0259	$ 0.0294	$ 0.0313	$ 0.0333
8	Demand Charge Secondary, per kW, per day	$ 0.3047	$ 0.3456	$ 0.3681	$ 0.3920
9	**Commercial - Medium 10 kW Min (ECMNM)**				
10	Access and Facilities Charge, per day	$ 1.0367	$ 1.1759	$ 1.2523	$ 1.3337
11	Access and Facilities Charge, per kWh	$ 0.0445	$ 0.0505	$ 0.0538	$ 0.0573
12	Demand Charge Secondary, per kW, per day	$ 0.4110	$ 0.4662	$ 0.4965	$ 0.5288
13	**Commercial - Large 50 kW Min (ECLNM)**				
14	Access and Facilities Charge, per day	$ 1.3448	$ 1.5253	$ 1.6244	$ 1.7300
15	Access and Facilities Charge, per kWh	$ 0.0414	$ 0.0470	$ 0.0501	$ 0.0534
16	Demand Charge Secondary, per kW, per day	$ 0.4110	$ 0.4662	$ 0.4965	$ 0.5288

Note : Proposed 2027-2029 rates are based on an annual 6.5% service increase applied to the 2025 rate, as approved by City Council for the Electric Service on November 12, 2024.

Colorado Springs Utilities
2027 Energy-Wise Net Metering Rate Option
Effective January 1, 2027

WORKSHEET 1.1 - RATE CALCULATION

Line No.	Rate Class	Classified Cost[1]								
		Customer Related			Energy Related			Demand Related		
(a)	(b)	(c)			(d)			(e)		
1	**Residential (ERNM)**									
2	Revenue Requirement	$	57,218,113		$	42,505,133		$	93,518,563	
3	Units		215,123			1,639,101,529			671,206	(2)
4	Revenue Requirement per Unit	$	0.7287	(3)	$	0.0259	(4)	$	0.3817	(5)
5	**Commercial - Small (ECSNM)**									
6	Revenue Requirement	$	6,598,941		$	2,366,306		$	4,149,347	
7	Units		24,810			91,250,527			37,314	(2)
8	Revenue Requirement per Unit	$	0.7287	(3)	$	0.0259	(4)	$	0.3047	(5)
9	**Commercial - Medium 10 kW Min (ECMNM)**									
10	Revenue Requirement	$	4,065,289		$	17,050,467		$	10,390,489	
11	Units		10,743			382,878,379			69,263	(2)
12	Revenue Requirement per Unit	$	1.0367	(3)	$	0.0445	(4)	$	0.4110	(5)
13	**Commercial - Large 50 kW Min (ECLNM)**									
14	Revenue Requirement	$	1,648,263		$	17,213,025		$	10,781,728	
15	Units		3,358			415,688,080			71,871	(2)
16	Revenue Requirement per Unit	$	1.3448	(3)	$	0.0414	(4)	$	0.4110	(5)

Notes :

(1) *Classified cost and billing determinants derived from 2025 Electric Cost of Service Study unless otherwised noted.*

(2) *Demand billing determinant units derived from 2025 Load Research Study.*

(3) *Revenue Requirement per Unit is calculated as Revenue Requirement divided by Units multiplied by 365 to derive the Customer Related Access and Facilities Charge, per day.*

(4) *Revenue Requirement per Unit is calculated as Revenue Requirement divided by Units to derive the Energy Related Access and Facilities Charge, per kWh.*

(5) *Revenue Requirement per Unit is calculated as Revenue Requirement divided by Units divided by 365 to derive the Demand Related Demand Charge, per kW, per day. The calculated rate is capped at the Cost of New Energy (CONE) estimated at $150 per kW, per year. Any unrecovered demand related revenue requirement above that cap is recovered in the energy related revenue requirement.*

Electric – Industrial Service

Large Load (ELL) Rate Schedule

Worksheet

Colorado Springs Utilities
2026 Industrial Service - Large Load (ELL) Rate Schedule Worksheet
Effective January 1, 2026

WORKSHEET - ELL Rate Calculation

Line No.	Description		Proposed Rates 2026	Proposed Rates 2027	Proposed Rates 2028	Proposed Rates 2029
(a)	(b)		(c)	(d)	(e)	(f)
1	Access and Facilities Charge, per day	(1)	$ 8.9065	$ 9.9664	$ 11.1524	$ 12.4795
2	Demand Charge Secondary, per kW, per day	(1)	$ 0.8593	$ 0.9616	$ 1.0760	$ 1.2040
3	System Support Charge, per kW,per day	(2)	$ 0.0859	$ 0.0962	$ 0.1076	$ 0.1204
4	Resource Adequacy Charge, per kW, per day	(3)	$ 0.4110	$ 0.4377	$ 0.4662	$ 0.4965

Notes :

(1) *Access and Facilities and Demand Charge based on Industrial Service - Large Power and Light rates (ELG, ELG-P). See Rate Table on Sheet No. 2.11.*

(2) *System Support Charge based on 10% of Demand Charge Secondary, per kW, per day.*

(3) *Resource adequacy Charge based on the Cost of New Energy (CONE) of $150.00, per kW, per year.*

UTILITIES RULES and REGULATIONS

(URR)

Utilities Rules and Regulations (URR) Report

Utilities Rules and Regulations (URR)

Colorado Springs Utilities' (Utilities) URR are a part of the collective Tariffs that govern Utilities in accordance with the Colorado Springs City Code. The URR establishes general and service specific terms and conditions. This report summarizes proposed changes to URR sheets.

1. **Electric Industrial Service – Large Load (ELL)**

   With the proposed addition of the ELL Rate Schedule, as detailed in the Electric Report, Utilities proposes changes to the URR Fee Table related to the Customer Responsibility for Electric Substation Facility Fees, Time and Materials charges for required transmission extensions or modifications, and Recovery Agreements for advance transmission facilities construction cost related to development of mixed use, commercial, and/or industrial sites.

2. **Large Load Study Fees**

   Utilities proposes modifications to URR provisions added in 2025 related to large load interconnection studies. Proposed changes are procedural clarifications and reductions to the minimum load sizes required for study fees.

3. **Hydraulic Analysis Report (HAR)**

   Utilities proposes the addition of $200/hr fee for simple HARs meeting requirements enabling them to be performed under the basic HAR fee of $1,600.

4. **Energy-Wise Net Metering**

   Utilities proposes modifications to Dynamic Rate Switching to incorporate Energy-Wise Net Metering.

5. **Other Clerical Changes or Corrections**

   Utilities proposes several clerical changes to URRs to add clarity and/or make administrative corrections. The full detail of proposed changes can be found in the proposed resolution and tariff sheets.

Utilities Rules and Regulations (URR) Resolution

RESOLUTION NO. ________-25

A RESOLUTION REGARDING CERTAIN CHANGES TO COLORADO SPRINGS UTILITIES' UTILITIES RULES AND REGULATIONS

WHEREAS, Colorado Springs Utilities (Utilities) proposed modifications to the Utilities Rules and Regulations; and

WHEREAS, Utilities proposed modification of Large Load Application Requirements reducing the minimum load size requiring payment of study fees and clarification of procedures; and

WHEREAS, Utilities proposed the addition of fees and modifications to electric line service standards related to Utilities' proposed addition of the Industrial Service – Large Load (ELL) Rate Schedule within Utilities' Electric Rate Schedules; and

WHEREAS, Utilities proposed the addition of new fees for hydraulic analysis report relating to minor applications; and

WHEREAS, Utilities proposed modification of Dynamic Rate Switching to incorporate Energy-Wise Net Metering; and

WHEREAS, Utilities proposed other clerical modifications; and

WHEREAS, Utilities proposed to make the Utilities Rules and Regulations changes effective January 1, 2026; and

WHEREAS, the details of the changes noted above are reflected in Utilities' 2026 Rate Case; and

WHEREAS, City Council finds Utilities' proposed modifications prudent; and

WHEREAS, Utilities provided public notice of the proposed changes and complied with the requirements of the City Code for changing its Utilities Rules and Regulations; and

WHEREAS, specific fees, policy changes, and changes to any terms and conditions of service are set out in the attached tariffs for adoption with the final City Council Decision and Order in this case.

NOW, THEREFORE, BE IT RESOLVED BY THE CITY COUNCIL OF THE CITY OF COLORADO SPRINGS:

Section 1. That Colorado Springs Utilities Tariff, City Council Volume No. 6, Utilities Rules and Regulations shall be revised as follows:

Effective January 1, 2026

City Council Vol. No. 6		
Sheet No.	**Title**	**Cancels Sheet No.**
Fourth Revised Sheet No. 13	GENERAL	Third Revised Sheet No. 13
Fourth Revised Sheet No. 14	GENERAL	Third Revised Sheet No. 14
First Revised Sheet No. 14.1	GENERAL	Original Sheet No. 14.1

Effective January 1, 2026

City Council Vol. No. 6		
Sheet No.	**Title**	**Cancels Sheet No.**
Second Revised Sheet No. 17	GENERAL	First Revised Sheet No. 17
Second Revised Sheet No. 18	GENERAL	First Revised Sheet No. 18
Third Revised Sheet No. 20	GENERAL	Second Revised Sheet No. 20
Second Revised Sheet No. 20.1	GENERAL	First Revised Sheet No. 20.1
Second Revised Sheet No. 56	ELECTRIC	First Revised Sheet No. 56
First Revised Sheet No. 57	ELECTRIC	Original Sheet No. 57
First Revised Sheet No. 58	ELECTRIC	Original Sheet No. 58
Original Sheet No. 58.1	ELECTRIC	
Second Revised Sheet No. 59	ELECTRIC	First Revised Sheet No. 59
Second Revised Sheet No. 60	ELECTRIC	First Revised Sheet No. 60
First Revised Sheet No. 63	ELECTRIC	Original Sheet No. 63
Second Revised Sheet No. 73	NATURAL GAS	First Revised Sheet No. 73
First Revised Sheet No. 92	WATER	Original Sheet No. 92

Effective January 1, 2027

City Council Vol. No. 6		
Sheet No.	**Title**	**Cancels Sheet No.**
Third Revised Sheet No. 21	GENERAL	Second Revised Sheet No. 21

Section 2. The attached Tariff Sheets, Council Decision and Order, and other related matters are hereby approved and adopted.

Dated at Colorado Springs, Colorado, this 28th day of October 2025.

____
Council President

ATTEST:

____
Sarah B. Johnson, City Clerk

Utilities Rules and Regulations (URR) Redline Tariff Sheets Effective January 1, 2026

UTILITIES RULES AND REGULATIONS

GENERAL

B. Fees

Utilities may charge and collect fees as described in the below table, by contract, or as established by City Code Section 14.8.109 for Stormwater service fees. For fees associated with the Development Annexation Application process, see Sections I.C., Development Fees and Section I.D. Annexation Application Fees.

DESCRIPTION	AMOUNT	REFERENCE
GENERAL		
Trip Fee and/or Restoration of Service Fee • Residential • Nonresidential • Additional charge for after-hours restorations (outside of Utilities normal working business hours)	 $70.00 $70.00 $40.00	General, Sheet Nos. 19, 37-38, 40
Standby Service Fee	$250.00	General, Sheet No. 20
Large Load ~~Interconnection~~ Study Fees • Electric Fee Advance Payment ○ 5 MW base fee ○ Additional charge per MW over 5 MW ○ 20 MW base fee ○ Additional charge per MW over 20 MW ○ 100 MW base fee ○ Additional charge per MW over 100 MW ○ 200 MW and greater fee • Natural Gas Fee • Water Fee • Wastewater Fee	 $5,000.00 $1,000.00 $35,000.00 $1,000.00 $150,000.00 $1,000.00 $250,000.00 $1,000.00 $2,000.00 $2,000.00	General, Sheet No. 20
Returned Payment Fee (whether returned/refused payment was attempted by check, EFT, debit/credit card or other means).	$30.00	General, Sheet No. 24
Opt-Out Program Fee (for nonstandard meters) • One-time fee to enter program • Quarterly manual read charge	 $109.00 $35.00	General, Sheet Nos. 45-46

UTILITIES RULES AND REGULATIONS

GENERAL

Fees – cont'd

DESCRIPTION	AMOUNT	REFERENCE
ELECTRIC		
Electric Transmission Extension and/or Modification Fees	Time and Materials Cost	Electric, Sheet No. 58
Electric Substation Facility Fees • Existing capacity • Capacity additions	 $150.00/kW Time and Materials Cost	Electric, Sheet No. 58
Electric Line Extension Fees (Single Service only) • Inspection and Connection Fee • Return Trip Fee (including late appointment cancellations) • Distribution Charge (Contribution in Aid of Construction) ○ Primary distribution line* ○ 3-phase 200 amp mainline ○ 3-phase 600 amp mainline ○ Additional charge for congested space * Commercial and industrial extensions are customer installed, with all trenching, compaction, etc.; all circuit-feet lengths are as estimated by Utilities. Primary distribution line fee not applicable.	 $585.00 $450.00 $60.47/linear foot $55.83/circuit foot Time and Materials Cost $11.55/linear foot	Electric, Sheet Nos. 59-65
Electric Temporary Service Connection Fee	$260.00	Electric, Sheet Nos. 65-66
Pedestal Damage Fee	Cost of Repairs	Electric, Sheet No. 66
Renewable Energy System Interconnection Application Review Fee • Less than or equal to 150 kW • Greater than 150 kW	 $100.00 $1,000.00	Electric, Sheet No. 67.1
~~**NATURAL GAS**~~		
~~Natural Gas Line Extension Fees (Single Service only)~~ • ~~Inspection and Connection Fee~~ • ~~Return Trip Fee~~ • ~~Inspection and Connection Fee for other polyethylene services less than 2" in diameter (Per Stub)~~ • ~~Distribution Charge (Contribution in Aid of Construction)~~ ○ ~~Natural Gas main and service stub~~ ○ ~~Natural Gas mainline~~ • ~~Less than 150 PSIG~~ • ~~Greater than or equal to 150 PSIG~~ ○ ~~Additional charge for congested space~~	 ~~$585.00~~ ~~$450.00~~ ~~$496.85~~ ~~$30.75/linear foot~~ ~~$33.71/linear foot~~ ~~Time and Materials Cost~~ ~~$11.55/linear foot~~	~~Natural Gas, Sheet Nos. 72-81~~

Approval Date: ~~November 12, 2024~~October 28, 2025
Effective Date: ~~January 1, 2025~~January 1, 2026
Resolution No. ~~174-24~~

UTILITIES RULES AND REGULATIONS

GENERAL

Fees – cont'd

DESCRIPTION	AMOUNT	REFERENCE
NATURAL GAS		
Natural Gas Line Extension Fees (Single Service only)		Natural Gas, Sheet Nos. 72-81
• Inspection and Connection Fee	$585.00	
• Return Trip Fee	$450.00	
• Inspection and Connection Fee for other polyethylene services less than 2" in diameter (Per Stub)	$496.85	
• Distribution Charge (Contribution in Aid of Construction)		
○ Natural Gas main and service stub	$30.75/linear foot	
○ Natural Gas mainline		
• Less than 150 PSIG	$33.71/linear foot	
• Greater than or equal to 150 PSIG	Time and Materials Cost	
○ Additional charge for congested space	$11.55/linear foot	
ELECTRIC AND NATURAL GAS LINE EXTENSION		
Electric and Natural Gas Fees (Joint Service)		Electric, Sheet Nos. 59-65 Natural Gas, Sheet Nos. 72-81
• Inspection and Connection Fee	$900.00	
• Inspection and Connection Fee for other polyethylene services less than 2" in diameter (Per Stub)	$779.32	
• Return Trip Fee (including late appointment cancellations)	$734.00	
• Electric Distribution Charge (Contribution in Aid of Construction)		
○ Primary distribution line*	$54.85/linear foot	
○ 3-phase 200 amp main line	$50.66/circuit foot	
○ 3-phase 600 amp main line	Time and Materials Cost	
○ Additional charge for congested space	$5.78/linear foot	
* Commercial and industrial extensions are customer installed, with all trenching, compaction, etc.; all circuit-feet lengths are as estimated by Utilities. Primary distribution line fee not applicable.		
• Natural Gas Distribution Charge (Contribution in Aid of Construction)		
○ Natural Gas main and service stub	$21.12/linear foot	
○ Natural Gas mainline		
• Less than 150 PSIG	$23.83/linear foot	
• Greater than or equal to 150 PSIG	Time and Materials Cost	
○ Additional charge for congested space	$5.78/linear foot	
• Cancellation Fees (Reduced in certain circumstances per Utilities' policy)	% of Applicable Return Trip Fee	Electric, Sheet No. 65 Natural Gas, Sheet No. 81
○ Step One Fee	10%	
○ Step Two Fee	25%	
○ Step Three Fee	50%	

UTILITIES RULES AND REGULATIONS

GENERAL

C. Development Fees (De minimis reviews are not charged development application fees.)

FEE	AMOUNT	PAYABLE AT TIME OF:
• City of Colorado Springs major development application review, per application	$800.00	Plan submittal to City Land Use Review
• City of Colorado Springs minor development application review, per application	$600.00	Plan submittal to City Land Use Review
• City of Manitou Springs development application review, per application	$200.00	Review of submittal
• El Paso County development application review, per application	$200.00	Review of submittal
• All other jurisdictions' development application review, per application	$200.00	Review of submittal
• Electric and/or gas line extension design* o Electric residential • Per extension contract, plus • Per lot o Electric commercial, per building o Natural Gas • Per extension contract, plus • Per service stub * Electric and/or gas line extension design fees not applicable Electric 3-phase 600 amp main line extensions and Natural Gas mainline extensions greater than 150 psig. Actual extension design cost included in Time and Materials Cost extension fees.	 $249.00 $49.50 $597.00 $249.00 $49.50	Submittal of extension contract, except electric commercial to be submitted at time of service contract
• Water or wastewater recovery agreement contract application fee o Contracts involving 50 acres or less o Contract involving more than 50 acres	 $2,210.00 $4,413.00	Submittal of recovery agreement request
• Water or wastewater recovery agreement processing fee, per service contract with recovery agreement reimbursements	$62.00	Service contract execution
• Utilities' preparation of Hydraulic Analysis Reports – Large Application, for sites 960 acres or greater ~~than 960 acres~~ • Revisions, per hour	$6,400.00 $200.00	Prior to Development Plan approval or upon invoicing
• Utilities' preparation of Hydraulic Analysis Reports – Complex Application, for sites greater than 40 acres and less than 960 acres, and located within multiple pressure zones • Revisions, per hour	$4,800.00 $200.00	Prior to Development Plan approval or upon invoicing

UTILITIES RULES AND REGULATIONS

GENERAL

Development Fees – cont'd

FEE	AMOUNT	PAYABLE AT TIME OF:
• Utilities' preparation of Hydraulic Analysis Reports – Moderately Complex Application, for sites greater than 40 acres and less than 960 acres, and located within a single pressure zone and no coordination with other pressure zones required and for sites ~~less than~~ 40 acres or less, and located within multiple pressure zones • Revisions, per hour	$3~~-~~,200.00 $200.00	Prior to Development Plan approval or upon invoicing
• Utilities' preparation of Hydraulic Analysis Reports – Basic Application, for sites greater than 10 acres and less than 40 acres and located with a single pressure zone and no coordination with other pressure zones required • Revisions, per hour	$1,600.00 $200.00	Prior to Development Plan approval or upon invoicing
• Utilities' preparation of Hydraulic Analysis Reports – Minor Application, for minor modifications to the existing system for sites 10 acres or less, per hour, not to exceed eight hours.	$200.00	Prior to Development Plan approval or upon invoicing
• Fire flow reports o New Development • Initial two fire flow reports - within twelve-month period • Additional reports, per hour with minimum one-hour charge o Existing Hydrant Reports* • First request, per site • Additional request, per site, per insistence *Refer to the current edition of the *Line Extension and Service Standards* – Water for form detailed information pertaining to fire flow report Charges	 $0.00 $200.00 $0.00 $50.00	Prior to construction plan approval or upon invoicing
• Utilities' preparation of Wastewater Analysis Report – Large Application, for sites greater than 960 acres • Revisions, per hour	$4,800.00 $200.00	Prior to Development Plan approval or upon invoicing
• Utilities' preparation of Wastewater Analysis Reports – Moderately Complex Application, for sites greater than 40 acres and less than 960 acres • Revisions, per hour	$3,200.00 $200.00	Prior to Development Plan approval or upon invoicing
• Utilities' preparation of Wastewater Analysis Reports – Basic Application, for sites less than 40 acres • Revisions, per hour	$1,600.00 $200.00	Prior to Development Plan approval or upon invoicing

Approval Date: ~~November 12, 2024~~October 28, 2025
Effective Date: ~~January 1, 2025~~January 1, 2026
Resolution No. ~~174-24~~

H. Development – Financial Responsibility for New Premises

The contractor or builder of a new or renovated Premises requesting or using utility services for that Premises will remain solely responsible for such services until both of the following occur: (i) a Certificate of Occupancy is issued by the Pikes Peak Regional Building Department for the Premises and (ii) another Customer assumes responsibility for the services for that Premises or the services for that Premises are terminated at the request of the contractor or builder.

I. Standby Service Fee

In accordance with City Code, a Standby Service Fee, applicable to, but not limited to standby services and relocations, will be charged associated with excavations near underground facilities. See Section I.B. Fee Table.

J. Large Load ~~Interconnection Study Fees~~Application Requirements

1. General

Subject to the terms and conditions of these Utilities Rules and Regulations, *Line Extension and Service Standards* for each service, and program rules, Customers (or potential Customers) requesting future utility services are required to complete ~~a request for reserving resource and distribution capacity application~~ an Application for entering capacity queue and any applicable provisions or requests related to Regional Transmission Organization (RTO) tariffs or procedures when potential new and/or expanding loads equal or exceed the following:

a. Electric – Five megawatts (MW)
b. Natural Gas – ~~Two and one-half Dth~~ 2.5 Dth per hour
c. Water – ~~One quarter of one million~~ 0.25 million gallons per day
d. Wastewater – ~~One-quarter of one million~~ 0.25 million gallons per day

2. Large Load ~~Interconnection~~ Study Fees and Fee Advance Payments

As defined in *Line Extension and Service Standards* for each service, request for potential new and/or expanding loads that equal or exceed the loads specifications provided in J.1. above ~~below~~ require payment of large load ~~interconnection~~ study fee(s) and/or fee advance payments(s), payable at the time of study request, for each service meeting or exceeding the load size as defined in this section. Large Load ~~Interconnection~~ Study Fees and Advance Payments are in addition to all other applicable fees and charges as defined in Utilities' tariffs, including these Utilities Rules and Regulation. Electric Large Load ~~Interconnection~~ Study Fee Advance

UTILITIES RULES AND REGULATIONS

GENERAL

Payments in the form of cash are required at the time of study request. ~~In the event actual electric study costs~~

In the event actual electric study costs exceed the advance payment amounts, the Customer will be required to pay the balance upon invoicing. In the event actual electric study costs are less than the advance payment amounts, the balance will be refunded to the Customer without interest. Natural Gas, Water and Wastewater fee amounts are payable at the time of study request and are non-refundable. See Section I.B. Fee Table.

~~a. Electric – 20 MW~~
~~b. Natural Gas – 10 Dth per hour~~
~~c. Water – One million gallons per day~~
~~d. Wastewater – One million gallons per day~~

3. Upon application and payment of applicable study fees, Utilities will review the feasibility and requirements of providing service for new and/or expanding loads. Subject to Utilities' study results and determination of feasibility and~~,~~ upon Customer payment of all fees and/or cost, Customers may ~~submit a written notice of intent to interconnect large load~~ proceed pursuant to these Rules and Regulations, Utilities' Rate Schedules, *Line Extension and Service Standards,* program rules, and contracts ~~in accordance with Utilities' program rules~~. Subject to availability, Utilities' services to large loads, as defined in this section, will be provided to eligible Customers on a first-come, first-served basis based on the date ~~notice of intent to interconnect large load~~ of application and payment of study fees~~is received by Utilities~~. Connection to a Utilities system requires Utilities approval, which is contingent upon the customer satisfying all requirements in Utilities' tariffs, including these Utilities Rules and Regulations, *Line Extension and Service Standards*, City Code, and all applicable program rules and policies.

II. STARTING SERVICE

A. Application and Financial Responsibility

1. Application

a. Persons requesting utility service must complete an application for service by contacting Utilities.

b. A natural person requesting utility service must be of full legal age. Utilities shall require some form of identification.

c. Utilities' acceptance of an application constitutes a binding contractual agreement between Utilities and the Customer, including all applicable provisions of Utilities' Tariffs.

d. Applicable fees must be paid at the start of service. See Section I.B. Fee Table.

VI. ELECTRIC

A. Electric Service Standards

1. Utility Provisions

Utilities will furnish, install at its expense, own and maintain the equipment to properly meter the service required except as specified under the Totalization Service charge in the Electric Rate Schedules, and the Automated-Meter Opt-Out Program.

All electric service will be metered except in limited circumstances. Customers may receive service without metering at tariffed rates pursuant to Electric Rate Schedule Sheet No. 5.1 or upon execution of a separate written agreement in which Utilities and the Customer agree upon usage estimation procedures. This separate written agreement option will be limited to instances when Electric Rate Schedule Sheet No. 5.1 is not available and when average, individual, commercial facility loads are estimated to be less than 66 kWh/day and when Utilities, at its sole discretion, (1) determines that metering is not appropriate or cost effective and (2) determines that a limited opportunity for load variance, misuse or subterfuge exists. At any time during the contract period, Utilities may check the Customer's usage and a meter(s) will be installed in a Customer-owned socket(s) if deemed necessary by Utilities.

Standard service consists of overhead service including an overhead service drop from the service line to the Customer's Premise. In the event underground service is desired or is required in an underground service area, the Customer will provide contributions in aid-of-construction. In some existing locations, if this equipment is on the load side of the Point of Common Coupling (PCC) (aka Service Point as defined by the National Electric Code), the customer is responsible to install or remove the Utilities metering equipment for maintenance and repair.

The Customer will pay the specified fee for design of Line Extensions.

a. Transmission Service~~Primary Service~~

This type of service (highest voltage located on the Customer's Premise) is alternating current, 60 hertz, three-phase, four wire wye, 115,000 or 230,000 volts. Customer must provide install, and maintain transformers(s)~~12,470/7,200 volts or 34,500/19,900 volts nominal~~.

~~This does not preclude Utilities from providing primary or secondary service to a customer at Utilities convenience, provided the service is metered and billed under the appropriate Electric Tariff.~~

UTILITIES RULES AND REGULATIONS

ELECTRIC

Electric – cont'd

b. Primary Service

This type of service (highest voltage located on the Customer's Premise) is alternating current, 60 hertz, three-phase, four wire wye, 12,470/7,200 volts or 34,500/19,900 volts nominal.

This does not preclude Utilities from providing primary or secondary service to a customer at Utilities convenience, provided the service is metered and billed under the appropriate Electric Tariff.

~~b.~~c. Secondary Service

This type of service is alternating current, 60 hertz, single or three phase.

Available secondary service nominal voltage classifications will depend upon a Customer's location and proximity to existing facilities as follows:

i. Single-phase, three wire, 120/240 volts;

ii. Single-phase, two wire, 120 volts;

iii. Single-phase, three wire, 120/208 volts;

iv. Three-phase, four wire, 120/208 volts wye;

v. Three-phase, four wire, 277/480 volts wye.

Totalized Service is available upon request at the rates and conditions provided for in the Totalization Service charge in the Electric Rate Schedules.

~~2. Customer Provisions~~

~~The Customer will provide, at the Customer's expense, a suitable mounting space or enclosure in an acceptable location for the installation of the metering equipment in accordance with the *Line Extension and Service Standards* for Electric. The Customer, as a condition of service, agrees to the original as-built location for those portions of the facilities on the Customer's Premise that are outside of a public utility easement or right of way. Any changes in location of the facilities will be at the sole expense of the Customer.~~

UTILITIES RULES AND REGULATIONS

ELECTRIC

~~a. Primary Service~~

~~All wiring, pole lines, conductors, transformers and other electric substation and distribution equipment beyond the point of metering, except Utilities' metering equipment, will be provided, owned, installed, and maintained at the Customer's expense.~~

~~b. Secondary Service~~

~~This type of service is alternating current, 60 hertz, single or three phase.~~

UTILITIES RULES AND REGULATIONS

ELECTRIC

Electric – cont'd

~~Available secondary service nominal voltage classifications will depend upon a Customer's location and proximity to existing facilities as follows:~~

~~i. Single-phase, three wire, 120/240 volts;~~

~~ii. Single-phase, two wire, 120 volts;~~

~~iii. Single-phase, three wire, 120/208 volts;~~

~~iv. Three-phase, four wire, 120/208 volts wye;~~

~~v. Three-phase, four wire, 277/480 volts wye.~~

~~Totalized Service is available upon request at the rates and conditions provided for in the Totalization Service charge in the Electric Rate Schedules.~~

~~3. Customer Provisions~~2. Customer Provisions

The Customer will provide, at the Customer's expense, a suitable mounting space or enclosure in an acceptable location for the installation of the metering equipment in accordance with the *Line Extension and Service Standards* for Electric. The Customer, as a condition of service, agrees to the original as-built location for those portions of the facilities on the Customer's Premise that are outside of a public utility easement or right of way. Any changes in location of the facilities will be at the sole expense of the Customer.

a. Transmission Service

All wiring, pole lines, conductors, transformers and other electric substation and distribution equipment beyond the point of metering, except Utilities' metering equipment, will be provided, owned, installed, and maintained at the Customer's expense. The Customer is responsible for the cost of engineering and construction of any extensions of and/or modifications to Utilities' transmission system as required by Utilities to provide service. Utilities will specify, purchase, maintain, and own the substation equipment and facilities on the Utilities side of the PCC. If required, the Customer will provide a suitable location for Utilities' equipment on their site. See Section I.B. Fee Table.

~~a.~~b. Primary Service

UTILITIES RULES AND REGULATIONS

ELECTRIC

All wiring, pole lines, conductors, transformers and other electric substation and distribution equipment beyond the point of metering, except Utilities' metering equipment, will be provided, owned, installed, and maintained at the Customer's expense. For Customers receiving Primary Service under the Industrial Service – Large Load Rate Schedule, unless Contribution in Aid of Construction payments have been made related to substation facilities to provide service to the Customer pursuant to a separate agreement, the Customer shall pay the Substation Facility Fee based on highest actual or expected load as established in the service agreement. Utilities will specify, purchase, maintain, and own equipment and facilities on the Utilities side of PCC. If required, the Customer will provide a suitable location for Utilities' equipment on their site. See Section I.B. Fee Table. Any subsequent increase in actual or expected load will be assessed additional Substation Facility Fees.

~~b. Secondary Service~~

~~The Customer will provide, at the Customer's expense, all inside wiring necessary for the proper utilization of the service. Utilities will require that the service entrance wiring, the meter loop, the service loop support and the service entrance switch be installed in accordance with the *Line Extension and Service Standards* for Electric. The service entrance wiring will be brought to a point outside the Premise that can be reached from the service line without service drop trespass upon other property.~~

UTILITIES RULES AND REGULATIONS

ELECTRIC

Electric – cont'd

c. Secondary Service

The Customer will provide, at the Customer's expense, all inside wiring necessary for the proper utilization of the service. Utilities will require that the service entrance wiring, the meter loop, the service loop support and the service entrance switch be installed in accordance with the *Line Extension and Service Standards* for Electric. The service entrance wiring will be brought to a point outside the Premise that can be reached from the service line without service drop trespass upon other property. For Customers receiving Secondary Service under the Industrial Service – Large Load Rate Schedule, unless Contribution in Aid of Construction payments have been made related to substation facilities to provide service to the Customer pursuant to a separate agreement, the Customer shall pay the Substation Facility Fee based on highest actual or expected load as established in the service agreement. Utilities will specify, purchase, maintain, and own equipment and facilities on the Utilities side of PCC. If required, the Customer will provide a suitable location for Utilities' equipment on their site. See Section I.B. Fee Table. Any subsequent increase in actual or expected load will be assessed additional Substation Facility Fees.

Electric – cont'd

~~4.~~ 3. Service Limitations

a. Instantaneous Demand

In order to protect Utilities' service and infrastructure, any Customer's equipment such as motors, welding equipment, X-ray equipment, furnaces, heat pumps, etc., will have such characteristics, or be equipped with control equipment of such design, that the instantaneous current requirements during starting or cyclic operation are limited so that voltage flicker will conform to Utilities' *Line Extension and Service Standards* for Electric. As a general rule, instantaneous starting current for motors of 10 horsepower or more is limited to approximately 300% of normal full load current.

For residential electric service, the use of any single-phase motor will be limited to 125 amps starting current at 240 volts. Any motor with greater starting current requires review and approval of Utilities prior to installation to assure that voltage flicker will conform to allowable *Line Extension and Service Standards* for Electric.

B. Electric Line Extensions and Services

Utilities, where economically sound and feasible, will extend transmission and distribution lines to place of delivery of service to a Customer in its certificated service area in accordance with the terms in this section. This will also apply to load expansions of existing Customers where additional facilities are required to serve them.

Extensions and connections to Utilities' facilities will be made in accordance with the Tariff and City Code.

1. Permanent Extension for Continuous Service

a. Extensions

A property Owner or developer is responsible for payment of all fees applicable to the extension of electric system infrastructure necessary to serve the Premise or development. Fees based on time and materials cost require advance payment of the entire estimated cost of design and construction, inclusive of excavation, boring, conduit, wire, vaults, concrete encasement, fill and compaction, switches, labor, restoration, permits, and easements. Fee payments are payable in advance of platting and development.

Electric – cont'd

See Section I.B Fee Table. Upon payment of all applicable fees, extensions will be constructed within 180 days after approval when construction and existence of such extension is economically sound and feasible.

b. Electric Recovery Agreement Charge:

i. Three-phase Mainline and Transmission Extensions:
The extension of three-phase mainline electric system infrastructure may provide for the service of adjacent unserved or undeveloped lands, or lands beyond the Premise or development. In such circumstances, Utilities may establish a Recovery Agreement with property Owner or developer to collect a pro rata share of the eligible 600 amp extension fees paid pursuant to Section VI.B.1.a. and interest, as provided in section VI.B.1.b.iii., Unit Recovery Charge Calculation, of these Rules and Regulations, from the property Owner or developer of such unserved or undeveloped lands at the time of connection to the facilities and refund such cost as provided in the Recovery Agreement. Utilities may establish Recovery Agreements, as provided in this section, related to transmission facilities constructed pursuant to agreements with developers of mixed use, commercial, and industrial sites.

If Utilities determines that extension of electric system infrastructure is in the best interest of Utilities to ~~provide~~ protect electric service to existing Customers, to allow for the continued development within the service area, and/or to provide benefit to the entire service area, Utilities may, at its sole discretion, extend the electric system infrastructure located outside the boundaries of the unserved or undeveloped land prior to payment of fees pursuant to Section VI.B.1.a. Utilities will recover the cost to design and construct such facilities, with interest, through a Recovery Agreement Charge from the property Owner or developer of unserved or undeveloped lands prior to connection to such facilities. Utilities may implement an Advance Recovery Agreement Charge to collect the cost of the facilities in advance of its construction. Advance Recovery Agreements are limited to Utilities' designated projects to the extent Utilities determines, at its sole discretion.

Electric – cont'd

~~b~~c. Underground Electric Service and Extensions

All electric service lines must be installed in accordance with Utilities' *Line Extension and Service Standards* for Electric.

In the event underground single-phase and/or three-phase primary distribution lines are installed, the Customer will pay a contribution-in-aid of construction equal to the difference in cost between an overhead and an underground system.

i. Underground Electric Service - Residential

a. General Conditions

The Owner, developer or Customer will install, or cause to be installed, at no cost to Utilities, all materials necessary for the connection of Residential electric service from the Utilities system to the Premise, including those Residential connections within Mobile Home Parks, developments and subdivided property in which only one building (consisting of a single-family residence up to a four-plex residence) is to be constructed on a single Premise with a single service. Such Residential electric service installations include all trenching, backfilling and restoration as well as materials necessary for the installation.

The Residential electric service installation shall become the property of Utilities on and after the date of its inspection and connection to the Utilities system.

The Owner, developer and Customer warrants to Utilities all materials and labor related to the Residential electric service installation from its point of connection to the Utilities system to the Premise for a period of three years from the date of its inspection and connection to the Utilities system. In the event of a defect in the Residential electric service installation during the three-year warranty period, then the Owner, developer and Customer immediately shall repair or replace the Residential electric service installation at no cost to Utilities. The Owner, developer and Customer

Natural Gas – cont'd

or lands beyond the Premise or development. In such circumstances, Utilities may establish a Recovery Agreement with property Owner or developer to collect a pro rata share of the eligible fees paid pursuant to Section VII.G.1.a. and interest, as provided in section VII.G.1.b.iii., Unit Recovery Charge Calculation, of these Rules and Regulations, from the property Owner or developer of such unserved or undeveloped lands at the time of connection to the facilities and refund such cost as provided in the Recovery Agreement.

If Utilities determines that extension of natural gas system infrastructure is in the best interest of Utilities to ~~provide~~ protect natural gas service to existing Customers, to allow for the continued development within the service area, and/or to provide benefit to the entire service area, Utilities may, at its sole discretion, extend the natural gas system infrastructure located outside the boundaries of the unserved or undeveloped land prior to payment of fees pursuant to Section VII.G.1.a. Utilities will recover the cost to design and construct such facilities, with interest, through a Recovery Agreement Charge from the property Owner or developer of unserved or undeveloped lands prior to connection to such facilities. Utilities may implement an Advance Recovery Agreement Charge to collect the cost of the facilities in advance of its construction. Advance Recovery Agreements are limited to Utilities' designated projects to the extent Utilities determines, at its sole discretion.

ii. Recovery Agreement Charge:
A Recovery Agreement Charge may be assessed for each connection to a natural gas mainline or other facility, where such line or facility is planned or constructed by Utilities or is the subject of a Recovery Agreement between Utilities and the property Owner(s) or developer who paid fees related to such line or facility. Consistent with such agreements, the charge will be in an amount which represents a pro rata share of the fees paid. Property Owner(s) or developer-initiated Recovery Agreements will be collected prior to issuance of a building permit. Utilities-initiated Recovery Agreements will be collected prior to issuance

Water – cont'd

Owners of property in designated enclave areas which are platted and which contain occupied dwellings are responsible for the cost of engineering, construction and materials of all Water Distribution Mains and appurtenances necessary to serve the proposed property. The extension will extend from the nearest public water distribution source to the furthest property line of the Owner. The Owner is eligible to recover a pro rata share of such facilities. Utilities may participate in the cost of such extension to the extent Utilities determines, in its sole discretion, that installation of water distribution facilities will sufficiently reduce operational expenses to justify the extension and that the extension is required for efficient and safe operation of the system.

All costs incidental to or resulting from the procurement by Utilities of any required easement or right-of way, whether obtained by dedication, contract, condemnation or otherwise is borne by the property Owner(s) or developer and may be includable in a Recovery Agreement.

All costs advanced by Utilities for construction of extensions may be recovered through Recovery Agreement charges for connection to the mains extended by Utilities prior to such connections.

If Utilities determines that extension of Water Distribution Mains are in Utilities' best interest to protect water service to existing Customers, allow for the continued development within the service area, and provide benefit to the entire service area, Utilities may, at its sole discretion, design and construct the Water Distribution Mains located outside the boundaries of the unserved or undeveloped land. Utilities will recover the cost to construct such facilities, with interest, through a Recovery Agreement charge from the Owner(s) or developer of unserved or undeveloped lands prior to connection to such facilities. Utilities may implement ~~a~~ an Advance Recovery Agreement charge to collect the cost of the facilities in advance of its construction. Advance Recovery Agreements are based on estimated costs and are limited to Utilities' designated projects to the extent Utilities determines, in its sole discretion.

2. Service Lines

All cost and expenses incidental to the installation and connection of a Water Service Line to a Premises will be borne by the Owner(s) of the Premises. The Owner(s) will indemnify Utilities for any loss or damage to Utilities that may directly or indirectly be occasioned by installation of such Water Service Line.

Utilities Rules and Regulations (URR) Redline Tariff Sheets

Effective January 1, 2027

UTILITIES RULES AND REGULATIONS

GENERAL

Starting Service – cont'd

3. Rate Selection

a. General

Customers are placed on Standard rate offerings based upon their type of service (residential, nonresidential) and the amount of product they consume during the month. Where available, customers may choose optional rate offerings in place of the Standard offering if they meet the qualifications set out in the Availability clause of the optional rate offering. The Customer is ultimately responsible for rate selection and for monitoring the account to ensure that the rate selection remains the best choice and use of utility services. Electric and gas residential rates are not available to master metered or nonresidential accounts.

b. Commercial and Industrial Rate Schedules Subject to Dynamic Rate Switching

Customers are placed on the appropriate Standard rate schedule based upon highest daily usage or highest maximum demand during any of the last 12 billing periods. Because the applicability to Customers of rate schedules varies based on usage and/or demand, Utilities billing system tracks the Customer's usage and/or demand and then each billing period places the Customer on the most appropriate rate schedule under Utilities Dynamic Rate Switching. Dynamic Rate Switching is applicable to electric service taken under Standard and Energy-Wise Plus Time-of-Day Options, and Energy-Wise Net Metering Options. Natural gas Dynamic Rate Switching is only applicable to service taken under Standard rate schedules. Should a Customer be switched to a different rate schedule through Dynamic Rate Switching, the Customer may request a one-time review and potential adjustment back to the previous rate schedule if the Customer can demonstrate to Utilities' satisfaction that a unique circumstance or infrequent event caused the change in usage. Utilities will analyze historical consumption patterns and information provided by the Customer to determine the appropriate rate schedule.

Utilities Rules and Regulations (URR) Final Tariff Sheets Effective January 1, 2026

UTILITIES RULES AND REGULATIONS

GENERAL

B. Fees

Utilities may charge and collect fees as described in the below table, by contract, or as established by City Code Section 14.8.109 for Stormwater service fees. For fees associated with the Development Annexation Application process, see Sections I.C., Development Fees and Section I.D. Annexation Application Fees.

DESCRIPTION	AMOUNT	REFERENCE
GENERAL		
Trip Fee and/or Restoration of Service Fee • Residential • Nonresidential • Additional charge for after-hours restorations (outside of Utilities normal working business hours)	 $70.00 $70.00 $40.00	General, Sheet Nos. 19, 37-38, 40
Standby Service Fee	$250.00	General, Sheet No. 20
Large Load Study Fees • Electric Fee Advance Payment ○ 5 MW base fee ○ Additional charge per MW over 5 MW ○ 20 MW base fee ○ Additional charge per MW over 20 MW ○ 100 MW base fee ○ Additional charge per MW over 100 MW ○ 200 MW and greater fee • Natural Gas Fee • Water Fee • Wastewater Fee	 $5,000.00 $1,000.00 $35,000.00 $1,000.00 $150,000.00 $1,000.00 $250,000.00 $1,000.00 $2,000.00 $2,000.00	General, Sheet No. 20
Returned Payment Fee (whether returned/refused payment was attempted by check, EFT, debit/credit card or other means).	$30.00	General, Sheet No. 24
Opt-Out Program Fee (for nonstandard meters) • One-time fee to enter program • Quarterly manual read charge	 $109.00 $35.00	General, Sheet Nos. 45-46

UTILITIES RULES AND REGULATIONS

GENERAL

Fees – cont'd

DESCRIPTION	AMOUNT	REFERENCE
ELECTRIC		
Electric Transmission Extension and/or Modification Fees	Time and Materials Cost	Electric, Sheet No. 58
Electric Substation Facility Fees • Existing capacity • Capacity additions	 $150.00/kW Time and Materials Cost	Electric, Sheet No. 58
Electric Line Extension Fees (Single Service only) • Inspection and Connection Fee • Return Trip Fee (including late appointment cancellations) • Distribution Charge (Contribution in Aid of Construction) ○ Primary distribution line* ○ 3-phase 200 amp mainline ○ 3-phase 600 amp mainline ○ Additional charge for congested space * Commercial and industrial extensions are customer installed, with all trenching, compaction, etc.; all circuit-feet lengths are as estimated by Utilities. Primary distribution line fee not applicable.	 $585.00 $450.00 $60.47/linear foot $55.83/circuit foot Time and Materials Cost $11.55/linear foot	Electric, Sheet Nos. 59-65
Electric Temporary Service Connection Fee	$260.00	Electric, Sheet Nos. 65-66
Pedestal Damage Fee	Cost of Repairs	Electric, Sheet No. 66
Renewable Energy System Interconnection Application Review Fee • Less than or equal to 150 kW • Greater than 150 kW	 $100.00 $1,000.00	Electric, Sheet No. 67.1

UTILITIES RULES AND REGULATIONS

GENERAL

Fees – cont'd

DESCRIPTION	AMOUNT	REFERENCE
NATURAL GAS		
Natural Gas Line Extension Fees (Single Service only)		Natural Gas, Sheet Nos. 72-81
• Inspection and Connection Fee	$585.00	
• Return Trip Fee	$450.00	
• Inspection and Connection Fee for other polyethylene services less than 2" in diameter (Per Stub)	$496.85	
• Distribution Charge (Contribution in Aid of Construction)		
○ Natural Gas main and service stub	$30.75/linear foot	
○ Natural Gas mainline		
• Less than 150 PSIG	$33.71/linear foot	
• Greater than or equal to 150 PSIG	Time and Materials Cost	
○ Additional charge for congested space	$11.55/linear foot	
ELECTRIC AND NATURAL GAS LINE EXTENSION		
Electric and Natural Gas Fees (Joint Service)		Electric, Sheet Nos. 59-65 Natural Gas, Sheet Nos. 72-81
• Inspection and Connection Fee	$900.00	
• Inspection and Connection Fee for other polyethylene services less than 2" in diameter (Per Stub)	$779.32	
• Return Trip Fee (including late appointment cancellations)	$734.00	
• Electric Distribution Charge (Contribution in Aid of Construction)		
○ Primary distribution line*	$54.85/linear foot	
○ 3-phase 200 amp main line	$50.66/circuit foot	
○ 3-phase 600 amp main line	Time and Materials Cost	
○ Additional charge for congested space	$5.78/linear foot	
* Commercial and industrial extensions are customer installed, with all trenching, compaction, etc.; all circuit-feet lengths are as estimated by Utilities. Primary distribution line fee not applicable.		
• Natural Gas Distribution Charge (Contribution in Aid of Construction)		
○ Natural Gas main and service stub	$21.12/linear foot	
○ Natural Gas mainline		
• Less than 150 PSIG	$23.83/linear foot	
• Greater than or equal to 150 PSIG	Time and Materials Cost	
○ Additional charge for congested space	$5.78/linear foot	
• Cancellation Fees (Reduced in certain circumstances per Utilities' policy)	% of Applicable Return Trip Fee	Electric, Sheet No. 65 Natural Gas, Sheet No. 81
○ Step One Fee	10%	
○ Step Two Fee	25%	
○ Step Three Fee	50%	

UTILITIES RULES AND REGULATIONS

GENERAL

C. Development Fees (De minimis reviews are not charged development application fees.)

FEE	AMOUNT	PAYABLE AT TIME OF:
• City of Colorado Springs major development application review, per application	$800.00	Plan submittal to City Land Use Review
• City of Colorado Springs minor development application review, per application	$600.00	Plan submittal to City Land Use Review
• City of Manitou Springs development application review, per application	$200.00	Review of submittal
• El Paso County development application review, per application	$200.00	Review of submittal
• All other jurisdictions' development application review, per application	$200.00	Review of submittal
• Electric and/or gas line extension design* o Electric residential • Per extension contract, plus • Per lot o Electric commercial, per building o Natural Gas • Per extension contract, plus • Per service stub * Electric and/or gas line extension design fees not applicable Electric 3-phase 600 amp main line extensions and Natural Gas mainline extensions greater than 150 psig. Actual extension design cost included in Time and Materials Cost extension fees.	 $249.00 $49.50 $597.00 $249.00 $49.50	Submittal of extension contract, except electric commercial to be submitted at time of service contract
• Water or wastewater recovery agreement contract application fee o Contracts involving 50 acres or less o Contract involving more than 50 acres	 $2,210.00 $4,413.00	Submittal of recovery agreement request
• Water or wastewater recovery agreement processing fee, per service contract with recovery agreement reimbursements	$62.00	Service contract execution
• Utilities' preparation of Hydraulic Analysis Reports – Large Application, for sites 960 acres or greater • Revisions, per hour	$6,400.00 $200.00	Prior to Development Plan approval or upon invoicing
• Utilities' preparation of Hydraulic Analysis Reports – Complex Application, for sites greater than 40 acres and less than 960 acres, and located within multiple pressure zones • Revisions, per hour	$4,800.00 $200.00	Prior to Development Plan approval or upon invoicing

UTILITIES RULES AND REGULATIONS

GENERAL

Development Fees – cont'd

FEE	AMOUNT	PAYABLE AT TIME OF:
• Utilities' preparation of Hydraulic Analysis Reports – Moderately Complex Application, for sites greater than 40 acres and less than 960 acres, and located within a single pressure zone and no coordination with other pressure zones required and for sites 40 acres or less, and located within multiple pressure zones • Revisions, per hour	$3,200.00 $200.00	Prior to Development Plan approval or upon invoicing
• Utilities' preparation of Hydraulic Analysis Reports – Basic Application, for sites greater than 10 acres and less than 40 acres and located with a single pressure zone and no coordination with other pressure zones required • Revisions, per hour	$1,600.00 $200.00	Prior to Development Plan approval or upon invoicing
• Utilities' preparation of Hydraulic Analysis Reports – Minor Application, for minor modifications to the existing system for sites 10 acres or less, per hour, not to exceed eight hours.	$200.00	Prior to Development Plan approval or upon invoicing
• Fire flow reports o New Development • Initial two fire flow reports - within twelve-month period • Additional reports, per hour with minimum one-hour charge o Existing Hydrant Reports* • First request, per site • Additional request, per site, per insistence *Refer to the current edition of the *Line Extension and Service Standards* – Water for form detailed information pertaining to fire flow report Charges	$0.00 $200.00 $0.00 $50.00	Prior to construction plan approval or upon invoicing
• Utilities' preparation of Wastewater Analysis Report – Large Application, for sites greater than 960 acres • Revisions, per hour	$4,800.00 $200.00	Prior to Development Plan approval or upon invoicing
• Utilities' preparation of Wastewater Analysis Reports – Moderately Complex Application, for sites greater than 40 acres and less than 960 acres • Revisions, per hour	$3,200.00 $200.00	Prior to Development Plan approval or upon invoicing
• Utilities' preparation of Wastewater Analysis Reports – Basic Application, for sites less than 40 acres • Revisions, per hour	$1,600.00 $200.00	Prior to Development Plan approval or upon invoicing

H. Development – Financial Responsibility for New Premises

The contractor or builder of a new or renovated Premises requesting or using utility services for that Premises will remain solely responsible for such services until both of the following occur: (i) a Certificate of Occupancy is issued by the Pikes Peak Regional Building Department for the Premises and (ii) another Customer assumes responsibility for the services for that Premises or the services for that Premises are terminated at the request of the contractor or builder.

I. Standby Service Fee

In accordance with City Code, a Standby Service Fee, applicable to, but not limited to standby services and relocations, will be charged associated with excavations near underground facilities. See Section I.B. Fee Table.

J. Large Load Application Requirements

1. General

Subject to the terms and conditions of these Utilities Rules and Regulations, *Line Extension and Service Standards* for each service, and program rules, Customers (or potential Customers) requesting future utility services are required to complete an Application for entering capacity queue and any applicable provisions or requests related to Regional Transmission Organization (RTO) tariffs or procedures when potential new and/or expanding loads equal or exceed the following:

a. Electric – Five megawatts (MW)
b. Natural Gas – 2.5 Dth per hour
c. Water – 0.25 million gallons per day
d. Wastewater – 0.25 million gallons per day

2. Large Load Study Fees and Fee Advance Payments

As defined in *Line Extension and Service Standards* for each service, request for potential new and/or expanding loads that equal or exceed the loads specifications provided in J.1. above require payment of large load study fee(s) and/or fee advance payments(s), payable at the time of study request, for each service meeting or exceeding the load size as defined in this section. Large Load Study Fees and Advance Payments are in addition to all other applicable fees and charges as defined in Utilities' tariffs, including these Utilities Rules and Regulation. Electric Large Load Study Fee Advance Payments in the form of cash are required at the time of study request.

In the event actual electric study costs exceed the advance payment amounts, the Customer will be required to pay the balance upon invoicing. In the event actual electric study costs are less than the advance payment amounts, the balance will be refunded to the Customer without interest. Natural Gas, Water and Wastewater fee amounts are payable at the time of study request and are non-refundable. See Section I.B. Fee Table.

3. Upon application and payment of applicable study fees, Utilities will review the feasibility and requirements of providing service for new and/or expanding loads. Subject to Utilities' study results and determination of feasibility and upon Customer payment of all fees and/or cost, Customers may proceed pursuant to these Rules and Regulations, Utilities' Rate Schedules, *Line Extension and Service Standards,* program rules, and contracts. Subject to availability, Utilities' services to large loads, as defined in this section, will be provided to eligible Customers on a first-come, first-served basis based on the date of application and payment of study fees. Connection to a Utilities system requires Utilities approval, which is contingent upon the customer satisfying all requirements in Utilities' tariffs, including these Utilities Rules and Regulations, *Line Extension and Service Standards*, City Code, and all applicable program rules and policies.

II. STARTING SERVICE

A. Application and Financial Responsibility

1. Application

a. Persons requesting utility service must complete an application for service by contacting Utilities.

b. A natural person requesting utility service must be of full legal age. Utilities shall require some form of identification.

c. Utilities' acceptance of an application constitutes a binding contractual agreement between Utilities and the Customer, including all applicable provisions of Utilities' Tariffs.

d. Applicable fees must be paid at the start of service. See Section I.B. Fee Table.

VI. ELECTRIC

A. Electric Service Standards

1. Utility Provisions

Utilities will furnish, install at its expense, own and maintain the equipment to properly meter the service required except as specified under the Totalization Service charge in the Electric Rate Schedules, and the Automated-Meter Opt-Out Program.

All electric service will be metered except in limited circumstances. Customers may receive service without metering at tariffed rates pursuant to Electric Rate Schedule Sheet No. 5.1 or upon execution of a separate written agreement in which Utilities and the Customer agree upon usage estimation procedures. This separate written agreement option will be limited to instances when Electric Rate Schedule Sheet No. 5.1 is not available and when average, individual, commercial facility loads are estimated to be less than 66 kWh/day and when Utilities, at its sole discretion, (1) determines that metering is not appropriate or cost effective and (2) determines that a limited opportunity for load variance, misuse or subterfuge exists. At any time during the contract period, Utilities may check the Customer's usage and a meter(s) will be installed in a Customer-owned socket(s) if deemed necessary by Utilities.

Standard service consists of overhead service including an overhead service drop from the service line to the Customer's Premise. In the event underground service is desired or is required in an underground service area, the Customer will provide contributions in aid-of-construction. In some existing locations, if this equipment is on the load side of the Point of Common Coupling (PCC) (aka Service Point as defined by the National Electric Code), the customer is responsible to install or remove the Utilities metering equipment for maintenance and repair.

The Customer will pay the specified fee for design of Line Extensions.

a. Transmission Service

This type of service (highest voltage located on the Customer's Premise) is alternating current, 60 hertz, three-phase, four wire wye, 115,000 or 230,000 volts. Customer must provide install, and maintain transformers(s).

UTILITIES RULES AND REGULATIONS

ELECTRIC

Electric – cont'd

b. Primary Service

This type of service (highest voltage located on the Customer's Premise) is alternating current, 60 hertz, three-phase, four wire wye, 12,470/7,200 volts or 34,500/19,900 volts nominal.

This does not preclude Utilities from providing primary or secondary service to a customer at Utilities convenience, provided the service is metered and billed under the appropriate Electric Tariff.

c. Secondary Service

This type of service is alternating current, 60 hertz, single or three phase.

Available secondary service nominal voltage classifications will depend upon a Customer's location and proximity to existing facilities as follows:

i. Single-phase, three wire, 120/240 volts;

ii. Single-phase, two wire, 120 volts;

iii. Single-phase, three wire, 120/208 volts;

iv. Three-phase, four wire, 120/208 volts wye;

v. Three-phase, four wire, 277/480 volts wye.

Totalized Service is available upon request at the rates and conditions provided for in the Totalization Service charge in the Electric Rate Schedules.

UTILITIES RULES AND REGULATIONS

ELECTRIC

Electric – cont'd

2. Customer Provisions

The Customer will provide, at the Customer's expense, a suitable mounting space or enclosure in an acceptable location for the installation of the metering equipment in accordance with the *Line Extension and Service Standards* for Electric. The Customer, as a condition of service, agrees to the original as-built location for those portions of the facilities on the Customer's Premise that are outside of a public utility easement or right of way. Any changes in location of the facilities will be at the sole expense of the Customer.

a. Transmission Service
All wiring, pole lines, conductors, transformers and other electric substation and distribution equipment beyond the point of metering, except Utilities' metering equipment, will be provided, owned, installed, and maintained at the Customer's expense. The Customer is responsible for the cost of engineering and construction of any extensions of and/or modifications to Utilities' transmission system as required by Utilities to provide service. Utilities will specify, purchase, maintain, and own the substation equipment and facilities on the Utilities side of the PCC. If required, the Customer will provide a suitable location for Utilities' equipment on their site. See Section I.B. Fee Table.

b. Primary Service
All wiring, pole lines, conductors, transformers and other electric substation and distribution equipment beyond the point of metering, except Utilities' metering equipment, will be provided, owned, installed, and maintained at the Customer's expense. For Customers receiving Primary Service under the Industrial Service – Large Load Rate Schedule, unless Contribution in Aid of Construction payments have been made related to substation facilities to provide service to the Customer pursuant to a separate agreement, the Customer shall pay the Substation Facility Fee based on highest actual or expected load as established in the service agreement. Utilities will specify, purchase, maintain, and own equipment and facilities on the Utilities side of PCC. If required, the Customer will provide a suitable location for Utilities' equipment on their site. See Section I.B. Fee Table. Any subsequent increase in actual or expected load will be assessed additional Substation Facility Fees.

Electric – cont'd

c. Secondary Service

The Customer will provide, at the Customer's expense, all inside wiring necessary for the proper utilization of the service. Utilities will require that the service entrance wiring, the meter loop, the service loop support and the service entrance switch be installed in accordance with the *Line Extension and Service Standards* for Electric. The service entrance wiring will be brought to a point outside the Premise that can be reached from the service line without service drop trespass upon other property. For Customers receiving Secondary Service under the Industrial Service – Large Load Rate Schedule, unless Contribution in Aid of Construction payments have been made related to substation facilities to provide service to the Customer pursuant to a separate agreement, the Customer shall pay the Substation Facility Fee based on highest actual or expected load as established in the service agreement. Utilities will specify, purchase, maintain, and own equipment and facilities on the Utilities side of PCC. If required, the Customer will provide a suitable location for Utilities' equipment on their site. See Section I.B. Fee Table. Any subsequent increase in actual or expected load will be assessed additional Substation Facility Fees.

Electric – cont'd

3. Service Limitations

a. Instantaneous Demand

In order to protect Utilities' service and infrastructure, any Customer's equipment such as motors, welding equipment, X-ray equipment, furnaces, heat pumps, etc., will have such characteristics, or be equipped with control equipment of such design, that the instantaneous current requirements during starting or cyclic operation are limited so that voltage flicker will conform to Utilities' *Line Extension and Service Standards* for Electric. As a general rule, instantaneous starting current for motors of 10 horsepower or more is limited to approximately 300% of normal full load current.

For residential electric service, the use of any single-phase motor will be limited to 125 amps starting current at 240 volts. Any motor with greater starting current requires review and approval of Utilities prior to installation to assure that voltage flicker will conform to allowable *Line Extension and Service Standards* for Electric.

B. Electric Line Extensions and Services

Utilities, where economically sound and feasible, will extend transmission and distribution lines to place of delivery of service to a Customer in its certificated service area in accordance with the terms in this section. This will also apply to load expansions of existing Customers where additional facilities are required to serve them.

Extensions and connections to Utilities' facilities will be made in accordance with the Tariff and City Code.

1. Permanent Extension for Continuous Service

a. Extensions

A property Owner or developer is responsible for payment of all fees applicable to the extension of electric system infrastructure necessary to serve the Premise or development. Fees based on time and materials cost require advance payment of the entire estimated cost of design and construction, inclusive of excavation, boring, conduit, wire, vaults, concrete encasement, fill and compaction, switches, labor, restoration, permits, and easements. Fee payments are payable in advance of platting and development.

Electric – cont'd

See Section I.B Fee Table. Upon payment of all applicable fees, extensions will be constructed within 180 days after approval when construction and existence of such extension is economically sound and feasible.

b. Electric Recovery Agreement Charge:

i. Three-phase Mainline and Transmission Extensions:
The extension of three-phase mainline electric system infrastructure may provide for the service of adjacent unserved or undeveloped lands, or lands beyond the Premise or development. In such circumstances, Utilities may establish a Recovery Agreement with property Owner or developer to collect a pro rata share of the eligible 600 amp extension fees paid pursuant to Section VI.B.1.a. and interest, as provided in section VI.B.1.b.iii., Unit Recovery Charge Calculation, of these Rules and Regulations, from the property Owner or developer of such unserved or undeveloped lands at the time of connection to the facilities and refund such cost as provided in the Recovery Agreement. Utilities may establish Recovery Agreements, as provided in this section, related to transmission facilities constructed pursuant to agreements with developers of mixed use, commercial, and industrial sites.

If Utilities determines that extension of electric system infrastructure is in the best interest of Utilities to protect electric service to existing Customers, to allow for the continued development within the service area, and/or to provide benefit to the entire service area, Utilities may, at its sole discretion, extend the electric system infrastructure located outside the boundaries of the unserved or undeveloped land prior to payment of fees pursuant to Section VI.B.1.a. Utilities will recover the cost to design and construct such facilities, with interest, through a Recovery Agreement Charge from the property Owner or developer of unserved or undeveloped lands prior to connection to such facilities. Utilities may implement an Advance Recovery Agreement Charge to collect the cost of the facilities in advance of its construction. Advance Recovery Agreements are limited to Utilities' designated projects to the extent Utilities determines, at its sole discretion.

Electric – cont'd

c. Underground Electric Service and Extensions

All electric service lines must be installed in accordance with Utilities' *Line Extension and Service Standards* for Electric.

In the event underground single-phase and/or three-phase primary distribution lines are installed, the Customer will pay a contribution-in-aid of construction equal to the difference in cost between an overhead and an underground system.

i. Underground Electric Service - Residential

a. General Conditions

The Owner, developer or Customer will install, or cause to be installed, at no cost to Utilities, all materials necessary for the connection of Residential electric service from the Utilities system to the Premise, including those Residential connections within Mobile Home Parks, developments and subdivided property in which only one building (consisting of a single-family residence up to a four-plex residence) is to be constructed on a single Premise with a single service. Such Residential electric service installations include all trenching, backfilling and restoration as well as materials necessary for the installation.

The Residential electric service installation shall become the property of Utilities on and after the date of its inspection and connection to the Utilities system.

The Owner, developer and Customer warrants to Utilities all materials and labor related to the Residential electric service installation from its point of connection to the Utilities system to the Premise for a period of three years from the date of its inspection and connection to the Utilities system. In the event of a defect in the Residential electric service installation during the three-year warranty period, then the Owner, developer and Customer immediately shall repair or replace the Residential electric service installation at no cost to Utilities. The Owner, developer and Customer

Natural Gas – cont'd

or lands beyond the Premise or development. In such circumstances, Utilities may establish a Recovery Agreement with property Owner or developer to collect a pro rata share of the eligible fees paid pursuant to Section VII.G.1.a. and interest, as provided in section VII.G.1.b.iii., Unit Recovery Charge Calculation, of these Rules and Regulations, from the property Owner or developer of such unserved or undeveloped lands at the time of connection to the facilities and refund such cost as provided in the Recovery Agreement.

If Utilities determines that extension of natural gas system infrastructure is in the best interest of Utilities to protect natural gas service to existing Customers, to allow for the continued development within the service area, and/or to provide benefit to the entire service area, Utilities may, at its sole discretion, extend the natural gas system infrastructure located outside the boundaries of the unserved or undeveloped land prior to payment of fees pursuant to Section VII.G.1.a. Utilities will recover the cost to design and construct such facilities, with interest, through a Recovery Agreement Charge from the property Owner or developer of unserved or undeveloped lands prior to connection to such facilities. Utilities may implement an Advance Recovery Agreement Charge to collect the cost of the facilities in advance of its construction. Advance Recovery Agreements are limited to Utilities' designated projects to the extent Utilities determines, at its sole discretion.

ii. Recovery Agreement Charge:
A Recovery Agreement Charge may be assessed for each connection to a natural gas mainline or other facility, where such line or facility is planned or constructed by Utilities or is the subject of a Recovery Agreement between Utilities and the property Owner(s) or developer who paid fees related to such line or facility. Consistent with such agreements, the charge will be in an amount which represents a pro rata share of the fees paid. Property Owner(s) or developer-initiated Recovery Agreements will be collected prior to issuance of a building permit. Utilities-initiated Recovery Agreements will be collected prior to issuance

Water – cont'd

Owners of property in designated enclave areas which are platted and which contain occupied dwellings are responsible for the cost of engineering, construction and materials of all Water Distribution Mains and appurtenances necessary to serve the proposed property. The extension will extend from the nearest public water distribution source to the furthest property line of the Owner. The Owner is eligible to recover a pro rata share of such facilities. Utilities may participate in the cost of such extension to the extent Utilities determines, in its sole discretion, that installation of water distribution facilities will sufficiently reduce operational expenses to justify the extension and that the extension is required for efficient and safe operation of the system.

All costs incidental to or resulting from the procurement by Utilities of any required easement or right-of way, whether obtained by dedication, contract, condemnation or otherwise is borne by the property Owner(s) or developer and may be includable in a Recovery Agreement.

All costs advanced by Utilities for construction of extensions may be recovered through Recovery Agreement charges for connection to the mains extended by Utilities prior to such connections.

If Utilities determines that extension of Water Distribution Mains are in Utilities' best interest to protect water service to existing Customers, allow for the continued development within the service area, and provide benefit to the entire service area, Utilities may, at its sole discretion, design and construct the Water Distribution Mains located outside the boundaries of the unserved or undeveloped land. Utilities will recover the cost to construct such facilities, with interest, through a Recovery Agreement charge from the Owner(s) or developer of unserved or undeveloped lands prior to connection to such facilities. Utilities may implement an Advance Recovery Agreement charge to collect the cost of the facilities in advance of its construction. Advance Recovery Agreements are based on estimated costs and are limited to Utilities' designated projects to the extent Utilities determines, in its sole discretion.

2. Service Lines

All cost and expenses incidental to the installation and connection of a Water Service Line to a Premises will be borne by the Owner(s) of the Premises. The Owner(s) will indemnify Utilities for any loss or damage to Utilities that may directly or indirectly be occasioned by installation of such Water Service Line.

Utilities Rules and Regulations (URR) Final Tariff Sheets Effective January 1, 2027

Starting Service – cont'd

3. Rate Selection

   a. General

      Customers are placed on Standard rate offerings based upon their type of service (residential, nonresidential) and the amount of product they consume during the month. Where available, customers may choose optional rate offerings in place of the Standard offering if they meet the qualifications set out in the Availability clause of the optional rate offering. The Customer is ultimately responsible for rate selection and for monitoring the account to ensure that the rate selection remains the best choice and use of utility services. Electric and gas residential rates are not available to master metered or nonresidential accounts.

   b. Commercial and Industrial Rate Schedules Subject to Dynamic Rate Switching

      Customers are placed on the appropriate Standard rate schedule based upon highest daily usage or highest maximum demand during any of the last 12 billing periods. Because the applicability to Customers of rate schedules varies based on usage and/or demand, Utilities billing system tracks the Customer's usage and/or demand and then each billing period places the Customer on the most appropriate rate schedule under Utilities Dynamic Rate Switching. Dynamic Rate Switching is applicable to electric service taken under Standard and Energy-Wise Plus Time-of-Day Options, and Energy-Wise Net Metering Options. Natural gas Dynamic Rate Switching is only applicable to service taken under Standard rate schedules. Should a Customer be switched to a different rate schedule through Dynamic Rate Switching, the Customer may request a one-time review and potential adjustment back to the previous rate schedule if the Customer can demonstrate to Utilities' satisfaction that a unique circumstance or infrequent event caused the change in usage. Utilities will analyze historical consumption patterns and information provided by the Customer to determine the appropriate rate schedule.

OPEN ACCESS TRANSMISSION TARIFF

(OATT)

Open Access Transmission Tariff (OATT) Report

Open Access Transmission Tariff Service (OATT)

Colorado Springs Utilities (Utilities) is a transmission provider and provides non-discriminatory wholesale high voltage electric service to itself and to its customers through the terms and conditions set forth in the OATT.

1. Southwest Power Pool (SPP) Regional Transmission Organization (RTO) Transition

Utilities' OATT was initially adopted in 2000 and revised periodically with updates in 2005, 2009, 2017-2019, and 2022. The updates in 2022 were driven by the opportunity to join the Western Energy Imbalance Service (WEIS) market, an SPP market offering, which balanced generation and load amongst regionally participating utilities. The participation in the WEIS market provided access to a larger pool of resources enabling cost savings for Utilities. With the success of the WEIS market, SPP is expanding its current RTO westward. Utilities is currently preparing to make the transition to join the SPP RTO when it expands in April 2026.

In joining the SPP RTO, Utilities' OATT will be rescinded in its entirety and Utilities will submit Transmission Owner filings to the SPP for incorporation into SPP's OATT. The effective date of this change is proposed to be on the day on which Utilities transfers functional control of its transmission facilities to SPP (currently scheduled for April 1, 2026 as of the date of this Rate Case Filing).

2. Additional Tariff Changes

With the transition to SPP not anticipated taking place until the second quarter of 2026, Utilities proposes one administrative clerical update in the Large Generator Interconnection Procedures (LGIP). The LGIP was revised in its entirety effective February 1, 2025, and Utilities proposes this clerical update with an effective date of November 1, 2025.

Open Access Transmission Tariff (OATT) Resolutions

RESOLUTION NO. ________-25

A RESOLUTION UPDATING AN ADMINISTRATIVE CHANGE IN THE COLORADO SPRINGS UTILITIES OPEN ACCESS TRANSMISSION TARIFF

WHEREAS, City Council approved the current effective interstate Open Access Transmission Tariff (OATT) by Resolutions 133-17, 75-18, 43-19, 93-22,190-22, and 14-25; and

WHEREAS, the current effective OATT sections related to the Standard Large Generator Interconnection Procedures (LGIP) were revised in their entirety effective February 1, 2025; and

WHEREAS, Colorado Springs Utilities (Utilities), upon subsequent review, observed the outside date for the allowable extension in requested Commercial Operation Date inadvertently reflected a date of December 31, 2027 which should have been December 31, 2029; and

WHEREAS, the City Council finds that the proposed modification will not adversely impact other customers; and

WHEREAS, the City Council finds that the proposed modification to the affected tariff sheet is just, reasonable, sufficient and not unduly discriminatory; and

WHEREAS, Utilities provided public notice of the proposed change and has complied with City Code for changing its OATT schedules; and

WHEREAS, Utilities has proposed the effective date for this change as November 1, 2025.

NOW, THEREFORE, BE IT RESOLVED BY THE CITY COUNCIL OF THE CITY OF COLORADO SPRINGS:

Section 1: That Colorado Springs Utilities Open Access Transmission Tariff, City Council Volume No. 3, shall be revised as follows:

Effective November 1, 2025

City Council Vol. No. 3		
Sheet No.	**Title**	**Cancels Sheet No.**
First Revised Sheet No. 219.17	Large Generator Interconnection Procedures	Original Sheet No. 219.17

Section 2: The attached sheets of the Open Access Transmission Tariff are hereby approved and adopted effective November 1, 2025 and shall remain in effect unless changed by subsequent Resolution of the City Council.

Dated at Colorado Springs, Colorado, this 28th day of October 2025.

____
City Council President

ATTEST:

____
Sarah B. Johnson, City Clerk

RESOLUTION NO. ________-25

A RESOLUTION RESCINDING THE COLORADO SPRINGS UTILITIES' OPEN ACCESS TRANSMISSION TARIFF IN CONJUNCTION WITH THE TRANSFER OF FUNCTIONAL CONTROL OF UTILITIES' TRANSMISSION FACILITIES TO SOUTHWEST POWER POOL REGIONAL TRANSMISSION ORGANIZATION

WHEREAS, City Council approved the current effective interstate Open Access Transmission Tariff (OATT) by Resolutions 133-17, 75-18, 43-19, 93-22,190-22, and 14-25; and

WHEREAS, Utilities proposed to pursue membership in the Southwest Power Pool (SPP) Regional Transmission Organization (RTO) effective in accordance with SPP's quarterly onboarding schedule of new RTO members in 2026; and

WHEREAS, Utilities proposed, from the effective date of the transfer of functional control of its transmission facilities to SPP, the requirement that the terms, conditions and rates of Utilities' transmission service be set forth in SPP's tariff; and

WHEREAS, Utilities proposed the rescission of its current OATT to no longer exist independently outside of SPP, effective upon the transfer of functional control of its transmission facilities to SPP; and

WHEREAS, if Utilities does become a member of SPP, the new formula rate template and implementation protocols for establishing an annual transmission revenue requirement applicable to Utilities set forth in SPP's tariff will supersede the existing rates set forth in Utilities' OATT.

NOW, THEREFORE, BE IT RESOLVED BY THE CITY COUNCIL OF THE CITY OF COLORADO SPRINGS:

Section 1: That effective on the day on which Utilities transfers functional control of Utilities' transmission facilities to SPP (scheduled for April 1, 2026, as of the date of this Resolution), Colorado Springs Utilities Open Access Transmission Tariff City Council Volume No. 3 is rescinded in its entirety.

Section 2: Utilities shall provide notification of the effective date of the rescission on its website (csu.org) and on its Open Access Same-Time Information System website.

Section 3. The attached Council Decision and Order, and other related matters are hereby approved and adopted.

Dated at Colorado Springs, Colorado, this 28th day of October 2025.

____
Council President

ATTEST:

____
Sarah B. Johnson, City Clerk

Open Access Transmission Tariff (OATT) Redline Tariff Sheets

Commercial Operation Date later than December 31, ~~2027~~2029.

All of the following must be included when an Interconnection Customer returns the Transitional Cluster Study Agreement:

(1) A selection of either Energy Resource Interconnection Service or Network Resource Interconnection Service.

(2) A deposit of five million dollars ($5,000,000) in the form of an irrevocable letter of credit, cash, a surety bond, or other form of security that is reasonably acceptable to Transmission Provider, where cash deposits will be treated according to Section 3.7 of this LGIP. If Interconnection Customer does not withdraw, the deposit shall be reconciled with and applied towards future construction costs described in the LGIA. Any amounts in excess of the actual construction costs shall be returned to Interconnection Customer within ninety (90) Calendar Days of the issuance of a final invoice for construction costs, in accordance with Article 12.2 of the LGIA. If Interconnection Customer withdraws or otherwise does not reach Commercial Operation, Transmission Provider must refund the remaining deposit once the final invoice for study costs and Transitional Withdrawal Penalty is settled.

(3) Exclusive Site Control for 100% of the proposed Generating Facility.

Transmission Provider shall conduct the Transitional Cluster Study and issue both an associated interim Transitional Cluster Study Report and an associated final Transitional Cluster Study Report. The interim Transitional Cluster Study Report shall provide the following information:

(1) identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;

Open Access Transmission Tariff (OATT) Final Tariff Sheets

Commercial Operation Date later than December 31, 2029.

All of the following must be included when an Interconnection Customer returns the Transitional Cluster Study Agreement:

(1) A selection of either Energy Resource Interconnection Service or Network Resource Interconnection Service.

(2) A deposit of five million dollars ($5,000,000) in the form of an irrevocable letter of credit, cash, a surety bond, or other form of security that is reasonably acceptable to Transmission Provider, where cash deposits will be treated according to Section 3.7 of this LGIP. If Interconnection Customer does not withdraw, the deposit shall be reconciled with and applied towards future construction costs described in the LGIA. Any amounts in excess of the actual construction costs shall be returned to Interconnection Customer within ninety (90) Calendar Days of the issuance of a final invoice for construction costs, in accordance with Article 12.2 of the LGIA. If Interconnection Customer withdraws or otherwise does not reach Commercial Operation, Transmission Provider must refund the remaining deposit once the final invoice for study costs and Transitional Withdrawal Penalty is settled.

(3) Exclusive Site Control for 100% of the proposed Generating Facility.

Transmission Provider shall conduct the Transitional Cluster Study and issue both an associated interim Transitional Cluster Study Report and an associated final Transitional Cluster Study Report. The interim Transitional Cluster Study Report shall provide the following information:

(1) identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;

TRANSMISSION OWNER FILING

Transmission Owner Filing Report

Colorado Springs Utilities

Colorado Springs Utilities (Utilities) is an Enterprise Fund of the City of Colorado Springs, Colorado ("City") that provides electric, streetlight, natural gas, water and wastewater services ("Utility System") to customers in the Pikes Peak region. The City of Colorado Springs' City Council's authority to establish rates, charges, and regulations for utility services is contained within the Colorado Constitution, Colorado Statutes, the Colorado Springs City Charter, the Colorado Springs City Code, and the Colorado Springs City Council's Rules and Procedures. The organization operates an electric generation, transmission and distribution system; a streetlight system; a natural gas distribution system; a water collection, treatment and distribution system; and a wastewater collection and treatment system. Utilities' service area includes the City, Manitou Springs and many of the suburban residential areas surrounding the City. The military installations of Fort Carson Army Base, Peterson Space Force Base and the United States Air Force Academy receive electric service, natural gas service and water service from Utilities. Peterson Space Force Base also receives wastewater treatment service and Cheyenne Mountain Space Force Station receives electric service. The City is currently the primary customer of the streetlight system and is responsible for the majority of streetlight service charges.

Utilities maintains financial and accounting records that utilize a chart of accounts in the Electric and Gas Services based primarily upon the uniform system of accounts prescribed by the Federal Energy Regulatory Commission (FERC) and in the Water and Wastewater Services based on the National Association of Regulatory Utility Commissioners (NARUC). Utilities develops rates to support the annual Budget. The basic sources of data used to develop rates include financial forecasting models and historical cost accounting data. The annual Budget is a critical data source that is prepared annually as part of the Annual Operating and Financial Plan.

Utilities prepares financial statements, in conformity with Generally Accepted Accounting Principles (GAAP) in the United States of America as applied to units of local governments and promulgated by the Governmental Accounting Standards Board (GASB). Utilities' financial statements do not purport to, and do not represent the financial position or the changes in the financial position of the City, component units or its joint ventures. Utilities' Annual Report and financial statements are provided on its website at csu.org.

Utilities is a transmission provider that currently provides non-discriminatory wholesale high voltage electric service through the terms and conditions set forth in its Open Access Transmission Tariff (OATT). Utilities' OATT was initially adopted in 2000 and revised periodically with updates in 2005, 2009, 2017, 2018, 2019, and 2022. The 2022 updates were driven by the opportunity to join the Western Energy Imbalance Service (WEIS) market, a Southwest Power Pool (SPP) market offering, which balanced generation and load amongst regionally participating utilities. The participation in the WEIS market provided access to a larger pool of resources enabling both cost savings and increased reliability for Utilities.

With the success of the WEIS market, SPP has obtained approval from FERC to expand its current Regional Transmission Organization (RTO) westward. Utilities is currently preparing to make the transition to join the SPP RTO when it expands in April 2026. With the continued evolution of an everchanging mix of power generation, rising cost of providing energy, and the challenges within Utilities associated with demand growth, this move is poised to continue to offer several financial and operational advantages, including improved efficiency in managing intra-hour energy imbalances and better integration of renewable energy sources across an even wider network of utilities.

1. Overview

As part of the transition to SPP, Utilities, as a Transmission Owner (TO) will transfer functional control of its transmission facilities to SPP but continue to own and maintain the physical infrastructure comprising its transmission system. Utilities' current OATT is proposed to be rescinded and Utilities will submit TO filings to SPP for incorporation into SPP's OATT. Generally, Utilities as a municipally owned entity, is not subject to the jurisdiction of FERC. However, FERC does regulate the wholesale electricity market, including transmission and sales between power generators and utilities to include the SPP RTO which requires justifying Utilities wholesale transmission rates in a different manner than historically done. Therefore, Utilities' rates and processes for updating its wholesale transmission have been prepared consistent with other municipal TO filings to regional transmission organizations and/or FERC.

Utilities' Annual Transmission Revenue Requirement (ATRR) in the current OATT was last updated and approved in 2017 by the City Council with rates phased in effective on January 1 of 2017, 2018 and 2019. The ATRR was calculated and supported through a Cost-of-Service Study and established rates for both Firm and Non-Firm Point-to-Point Transmission Service. In preparation for this transition into the SPP RTO, Utilities is submitting this OATT filing to modify certain schedules and attachments. The primary objectives of these proposed modifications are to:

- Establish a Transmission Formula Rate (TFR) template and protocols, anticipated to be submitted to SPP as part of their filing with FERC and updated annually after approved membership in SPP in accordance with the associated TFR implementation protocols.
- Utilize the TFR methodology to establish the initial updated ATRR and associated rates for both Firm and Non-Firm Point-to-Point Transmission Service to the projected cost of service to ensure adequate revenue recovery in 2026 and in which revenue requirement and charges will be updated annually thereafter while a member of SPP's RTO in accordance with the associated TFR implementation protocols.

2. Transmission Formula Rate Template and Implementation Protocols

Given the upcoming transition to SPP membership, Utilities is taking proactive steps with this filing to establish a TFR. TFR methodologies are approved by FERC and, upon approval, allow utilities to input historical and projected data to calculate the cost of service and subsequent rates on an annual basis. The formula defines the methodology and various inputs for determining the utility's cost of service. These inputs include, but are not limited to, the rate base (Electric Plant in-service plus adjustments), depreciation and amortization expenses, operation and maintenance expenses, administrative and general expenses, and rates for taxes other than income tax (such as Surplus Payments to the City and Bond Covenant Requirements). All inputs and data must be supported by additional information adequately describing how the inputs are derived. As Utilities is not required and therefore does not compile and file a FERC Form 1 report, many of the key inputs to the TFR for calculating the projected ATRR or reflecting the historical costs to be used for True-Up calculations are summarized through various workpapers compiled from internal software systems and records. The formula rate takes these data inputs for a rate year and applies historical revenues collected in that year resulting in an under-collection or over-collection. This true-up mechanism derives a value that, in addition to any necessary prior period adjustments, including applicable interest, is then added to forecasted or projected expenses less any revenue credits to arrive at a Net Revenue Requirement for the projected rate year.

Utilities 2026 ATRR has been prepared utilizing its TFR which incorporates the cash basis approach (cash flow) of the prior cost of service methodology. Utilities is an enterprise of the City of Colorado Springs, and as a governmental entity, is tax exempt. As such, Cost of Service has historically utilized this cash-needs basis for setting rates and therefore does not calculate a return on the rate base. Annually, City Council approves Utilities' budget. Utilities proposes to use budgeted projected values to populate the TFR for each calendar year in order to calculate the annually updated ATRR. Utilities anticipates that these rates will go into effect on the effective date of the transfer of functional control of Utilities transmission facilities to SPP.

Assuming the necessary regulatory approvals are issued, Utilities proposes an effective date of April 1, 2026. As such, the initial rate period for calculating a proposed formula rate is calendar year 2026, but the initial rates will be in effect for a partial year from the effective date of Utilities transfer of functional control of its transmission facilities to SPP through December 31, 2026.

The methodology for calculating Utilities proposed formula rate is largely aligned with the original methodology used in the currently effective ATRR by utilizing the same transmission-related cost components and incorporates similar allocator bases for those functionalized cost components. The TFR comprises three main components. The first is a statement of the ATRR that will be included as part of Attachment H of the SPP OATT as well as the underlying rates for Schedule 7 Long-Term Firm and Short-Term Firm Point-to-Point Transmission Service, and for Schedule 8 Non-Firm Point-to-Point Transmission Service. The second component is the formula itself with the tables that will also be included in Attachment H. Finally, Utilities' Protocols describe how Utilities will implement and update its transmission rates each year, what the review procedures will be, how customer challenges will be resolved, and how any changes to the annual rate updates will be implemented. These Utilities' Protocols will be included in the SPP OATT Attachment H. When the proposed rate becomes effective, SPP will post the populated TFR, including the worksheets and Utilities' Protocols, on its website.

3. Transmission Formula Rate Template Calculation of the Projected ATRR

All Tables included in the Formula Rate Template that are referenced herein can be found at the end of this report. Table P1 outlines the calculation for Utilities Projected ATRR while Table T2 outlines the calculation of a historical ATRR based on actuals which would be used, alongside actual revenues for calculating the over-collection or under-collection to be added to the projected ATRR. Table P1 (Projected ATRR) and Table T2 (ATRR) have the same layout in the template, and line references for expenses in Table T2 (ATRR) correspond to those in Table P1 (Projected ATRR) for reference to projected expenses. The major sections of the calculations are Operating Expenses (Line 14), Capital Projects Expense (Line 29), and Other Taxes (Line 42). These items, in addition to a Bond Covenant Requirement (Line 47) comprise the total gross ATRR (Line 48). Any Revenue credits (Line 49) are identified and offset the ATRR for a total net ATRR (Line 50) that is carried over to Table T1, Line 1 as the Projected ATRR.

a. Total Operating Expenses include:

1) Transmission O&M Expense (Table T2, Line 1) is reflected in Table E1, with actuals incurred in 2024 as well as projected to be incurred in calendar year 2026, and listed

by transmission account, consistent with the FERC Uniform System of Accounts. The amount of Transmission O&M incurred for this period is approximately $5.9M. Utilities TFR excludes Account 561 Load Dispatch expenses which are recovered in the charge for Schedule 1, and Account 565 Transmission by Others (if any).

2) Administrative and General Expense (Table T2, Line 11) is reflected in Table E2 consistent with the FERC Uniform System of Accounts with actuals incurred in 2024 and projected to be incurred in calendar year 2026. With Utilities being a four-service utility, total company A&G is allocated to each service using the Massachusetts method of allocating A&G. This method is a multi-factor approach that uses an equally weighted average of three ratios: direct labor, plant in service and total revenue. These expenses for the Electric service are then further allocated based on a factor derived by actual Transmission-specific labor applied against total actual labor. This allocation factor is calculated to be 10.37% and when applied against the actual A&G expenses, yields approximately $7.8M of A&G. Table T2, lines 6 and 7 remove all FERC annual fees, Regulatory Commission Expenses, EPRI dues and non-safety advertising. Line 10 includes only Regulatory Commission Expenses related to transmission. For this projected rate year, Utilities has assumed zero values to be entered for lines 6, 7, and 10.

3) Electric common plant O&M (if any) in line 12 and transmission lease payments in line 13 are the final two items comprising Total Operating Expenses.

b. Total Capital Projects Expenses include:

1) Debt Service Expense (Table T2, Line 15) is shown from the calculation of total Electric Debt Service as reflected on Table C3 and then allocated based on the transmission percentage of total gross plant. In debt issuances, Utilities, as a four-service utility, first examines capital projects that need to be funded, either from bond issuances or cash and wholistically assesses the importance or criticality of each project in its projections for funding needs across each service. Once those projects are identified and planned, Utilities then assesses the required project funding needs to determine planned financing in conjunction with planned cash funding, to meet the required needs while still balancing critical financial metric targets related to debt coverage, debt ratio, and days cash on hand. Utilities then executes the planned financing through bond issuances. The debt service schedules on Table C3 specifically outline how much principal and interest is associated with the issuance and how much is attributed to the Electric service. These issuances and their allocated Electric

percentages for principal and interest obligations are totaled up along with any actual debt that may have concluded in that year.

2) Cash-Funded New Construction Assets allocated to Transmission (Table T2, Line 24) starts with the actual Capital Additions assigned by function. Directly assigned Transmission Plant additions are combined with a portion of General Plant additions, based on the transmission percentage of total gross plant. A cash-funded allocator, derived from total actual cash funded capital against the total actual gross Electric plant additions from the prior 13 months, is then applied to the total Electric Capital assigned and allocated to Transmission yielding the actual total Cash Funding New Construction needs allocated to Transmission.
3) Amortization of Premium or Discount (Table T2, Line 27) is reflected on Table C4. These projected values are captured from accounts 428 and 429, consistent with the FERC Uniform System of Accounts. Then, with the same Electric percentages for a given issuance reflected with the debt service schedules, those values are totaled and then allocated further based on the transmission percentage of total gross plant.

c. Other Taxes include:

1) Surplus Payments to the City and Franchise Fees (Table T2, Line 41) is reflected on Line 39. As mentioned earlier, Utilities is an enterprise of the City of Colorado Springs. As a governmental entity, Utilities is a tax-exempt entity. However, the City Charter of the City of Colorado Springs (City) provides for the appropriation of any remaining surplus of net earnings to the general revenues of the City. Pursuant to its authority as the legislative body for the City and as the ratemaking body for Utilities, City Council has established planned Surplus Payments to the City of Colorado Springs for Utilities' Electric services. These payments are assessed on a fixed rate per kWh of actual sales inside the city. Additionally, Utilities Electric service incurs Franchise Fees expense related to providing Electric services to customers residing in other neighboring cities or municipalities. The Surplus Payments to City and Franchise Fees expense is allocated to Transmission using the Net Plant Allocator (Table T3, Line 17).
2) The TFR provides for Labor-Related Taxes (Table T2, Line 33) and Plant-Related Taxes (Table T2, Line 38), but Utilities is not projected to include either in this ATRR filing.

d. Other Revenue Requirement items include:

1) Bond Covenant Requirement is reflected on Table T2, Line 47. Strong financial metrics are an important aspect of maintaining bond ratings which can influence the interest rates Utilities pays on its debt. High ratings generally lead to lower borrowing

costs which keep costs down overall for ratepayers. In order to maintain the favorable ‘AA” rating, Utilities must show adequate debt service coverage in addition to other metrics. Stable industries such as utilities usually find debt service coverage ratio in the range of 1.25 to 1.5 as adequate. Utilities has included 1.3, in accordance with its bond covenant requirements and then allocated based on the transmission percentage of total gross plant.

2) Revenue credit offset is based on other Electric revenues included in Account 456.1, consistent with the FERC Uniform System of Accounts. For this projected rate year, Utilities has not projected any revenue credits to be included in its ATRR.

4. Transmission Revenue True-Up Mechanism

Historically, Utilities’ OATT utilized a stated rate approach where the projected ATRR was updated as needed and brought forward in a rate case before City Council, serving as Utilities regulatory body. In anticipation of transitioning to the SPP RTO, Utilities proposes to incorporate a true-up mechanism in the TFR. This adjustment will compare Utilities actual costs incurred during the calendar rate year to the actual revenues generated by the ATRR and resulting rates during the same period. Any over-recovery or under-recovery will be reflected as a reduction or increase to the Annual Update in the following projected year. Since 2026 will be the first year in the SPP RTO, Utilities does not have true up data from 2024 to incorporate in the 2026 projections. As a placeholder, Utilities has set the actual revenues equal to the actual revenue requirement for 2024 to nullify any increase or reduction to the projected 2026 ATRR. Utilities expects to incorporate a 2026 true up calculation to include applicable interest calculated in accordance with 18 C.F.R. § 35.19a, in 2027 for the projected 2028 ATRR.

5. TFR Peak Transmission Load Divisor

The calculation of Utilities Peak Transmission Load Divisor (Table T1, Line 3) is reflected on Table T4. For the 12-month period of January 2024 to December 2024, Utilities determined the day and hour of its peak network load for each month and then added to this the load amount associated with known entities taking firm network service. In order to represent the future energy needs for the region under normal weather conditions for each month, projecting the monthly load values for 2026, which are reflected on Table P5, incorporates historical peak loads, economic drivers, and spot load forecast additions. The average monthly peak load (12 coincident peak methodology) is used as the rate divisor to determine the underlying rates for service under Schedule 7 Long-Term Firm and Short-Term Firm (Table 1, Lines 4-10) Point-to-Point and Schedule 8 Non-Firm (Table 1, Lines 11-16) Point-to-Point Transmission Service.

6. TFR and Annual Update Implementation Protocols

Accompanying the TFR are implementation protocols (Protocols) which is the last component of the template. As mentioned earlier, these are procedures governing how the transmission rates are calculated and updated. They also establish how interested parties can submit discovery requests, review, verify and challenge the annual rate updates and the timelines associated with the procedures.

As outlined in the Protocols accompanying the TFR, no later than September 1 of each year, Utilities shall calculate its projected ATRR for the following year in accordance with the TFR that will be included in Attachment H of SPP's Tariff. These Protocols are based on the existing public process that Utilities has in place for reviewing proposed tariff changes. Interested parties will have the opportunity to submit written questions and responses to those written questions will be posted on the SPP website, OASIS, and Utilities website (csu.org). Additionally, Utilities will host a meeting to provide an opportunity for oral and written comments. Upon conclusion of the process, the final ATRR and resulting rates will be submitted to SPP for posting on its website prior to the January 1 effective date of such rates.

7. ATRR established using the TFR and Summary

The resulting ATRR for 2026 is shown on Table T1, Line 1 of the template in the amount of $34,281,960. In addition to the resulting updated projected 2026 ATRR, the transmission charges outlined in FERC's pro-forma Schedules 7 and 8, as referenced earlier in Section 5 of this Report, will be updated. The difference between Schedules 7 and 8 is that the non-firm (Schedule 8) point-to-point transmission service shall not exceed one month's reservation for any one application.

The TFR, 2026 ATRR, and Schedule 7 and 8 rates, and the accompanying implementation protocols will be filed with FERC via SPP on behalf of Utilities. Additionally, for purposes of the FERC filing, in lieu of this report, Utilities will submit prepared direct testimony which encapsulates the information provided herein as that approach is more typical to FERC filings. This filing that SPP will make on Utilities behalf will outline how the ATRR and rates for Firm and Non-Firm Point-to-Point Service are calculated. The TFR methodology will facilitate annual updates without the burden of filing rate cases, thereby streamlining the process and ensuring alignment with regulatory requirements.

In conclusion, Utilities' preparation for joining the SPP RTO represents a strategic move to enhance operational efficiency, achieve financial savings, and ensure compliance with regulatory standards. The proposed changes and the establishment of a TFR are pivotal steps in this process, paving the way for a smoother transition and long-term benefits for Utilities and its customers.

8. Formula Rate Template Tables

The Tables which comprise and reflect the calculation of the Formula Rate are included in this filing in the following section titled Transmission Owner Filing Formula Rate Tables Populated for referencing within this report.

Transmission Owner Filing

Resolution

RESOLUTION NO. ________-25

A RESOLUTION ADOPTING TRANSMISSION FORMULA RATE TEMPLATE AND THE IMPLEMENTATION PROTOCOLS FOR ESTABLISHING AN ANNUAL TRANSMISSION REVENUE REQUIREMENT FOR TRANSMISSION OWNER FILING SUBMITTALS FOR THE SOUTHWEST POWER POOL REGIONAL TRANSMISSION ORGANIZATION'S OPEN ACCESS TRANSMISSION TARIFF

WHEREAS, Utilities proposed to pursue membership in the Southwest Power Pool (SPP) Regional Transmission Organization (RTO) effective in accordance with SPP's quarterly onboarding schedule of new RTO members in 2026; and

WHEREAS, Utilities proposed to transfer functional control of its transmission facilities to SPP while continuing to own and maintain said infrastructure of its transmission system; and

WHEREAS, Utilities proposed to implement a formula rate template (Template) and implementation protocols (Protocols) (together the Formula Rate), so long as approved by the Federal Energy Regulatory Commission (FERC), to establish the mechanism and process for annual calculation, to include any true-up and updates, of the Annual Transmission Revenue Requirement (ATRR) and underlying calculated rates for Network Integration Transmission Service (NITS), Point-to-Point Transmission Service in the Colorado Springs Utilities (CSU) zone of the SPP footprint, as well as the ATRR for Base Plan Upgrades and other network upgrades; and

WHEREAS, Utilities proposed to establish the Formula Rate and the 2026 ATRR with its underlying calculated rates to be effective on the day on which Utilities transfers functional control of Utilities' transmission facilities to SPP (scheduled for April 1, 2026, as of the date of this Resolution); and

WHEREAS, Utilities proposed to follow the established Protocols to adjust the CSU zonal ATRR and underlying calculated rates on an annual basis based on Utilities' projected cost-of-service and load for the prospective rate year, including the required true-up adjustment (Annual Update), and to provide the Annual Update to SPP for posting on its website and submit such Annual Update to the FERC as an informational filing; and

WHEREAS, if Utilities does become a member of SPP, the new formula rate and the 2026 ATRR with its underlying calculated rates, set forth in SPP's tariff will supersede the existing rates in the Colorado Springs Utilities' Open Access Transmission Tariff.

NOW, THEREFORE, BE IT RESOLVED BY THE CITY COUNCIL OF THE CITY OF COLORADO SPRINGS:

Section 1: That effective on the day on which Utilities transfers functional control of Utilities' transmission facilities to SPP (scheduled for April 1, 2026, as of the date of this Resolution), Colorado Springs Utilities' formula rate template and the implementation protocols for establishing the mechanism and process for annual calculation, to include any true-up and updates, of its Annual Transmission Revenue Requirement (ATRR) and underlying calculated rates, so long as approved by the Federal Energy Regulatory Commission, shall remain in effect unless changed by subsequent transmission owner filings to SPP.

Section 2: That effective on the day of on which Utilities transfers functional control of Utilities' transmission facilities to SPP (scheduled for April 1, 2026, as of the date of this Resolution), Colorado Springs Utilities' initial 2026 ATRR and underlying calculated rates for Network Integration Transmission Service (NITS), Point-to-Point Transmission Service in the Colorado Springs Utilities (CSU) zone of the SPP footprint, as well as the ATRR for Base Plan Upgrades and other network upgrades, are approved and adopted and shall remain in effect unless changed by subsequent Utilities' Annual Updates.

Section 3. The attached formula rate template, implementation protocols, supporting documents, Council Decision and Order, and other related matters are hereby approved and adopted.

Dated at Colorado Springs, Colorado, this 28th day of October 2025.

____
Council President

ATTEST:

____
Sarah B. Johnson, City Clerk

Transmission Owner Filing

Formula Rate Tables

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Colorado Springs Utilities
Formula Rate Workbook
Projections for Rate Year 2026

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Colorado Springs Utilities
Formula Rate Workbook
Projections for Rate Year 2026

Table T1

Table T1: Transmission Rate Calculation

Projections for Rate Year 2026

Line No.	Item	Unit	Source/Calculation	Actual	Projected
[1]	Transmission Revenue Requirement Net of Revenue Credits	$/year	Table T2 or Table P1: [50]	$ -	$ -
[2]	True-Up (if Applicable)	$/year	Table P3: [14]	n/a	$ -
[3]	Peak Transmission Load	kW	Table T4: [15] or Table P5: [15]		
	Schedule 7: Long-Term Firm and Short-Term Point-to-Point Transmission Service				
	The charges are as follows:				
[4]	Yearly Delivery	$/kW-year	([1] + [2]) / [3]	$ -	$ -
[5]	Monthly Delivery	$/kW-month	[4] / 12	$ -	$ -
[6]	Weekly Delivery	$/kW-week	[4] / 52	$ -	$ -
[7]	Daily On-Peak Delivery	$/kW-day	[4] / 270	$ -	$ -
[8]	Daily Off-Peak Delivery	$/kW-day	[4] / 365	$ -	$ -
[9]	Hourly On-Peak Delivery	$/kWh	[7] / 16	$ -	$ -
[10]	Hourly Off-Peak Delivery	$/kWh	[8] / 24	$ -	$ -
	Schedule 8: Non-Firm Point-to-Point Transmission Service				
	The charges can be up to the following limits:				
[11]	Monthly Delivery	$/kW-month	[4] / 12	$ -	$ -
[12]	Weekly Delivery	$/kW-week	[4] / 52	$ -	$ -
[13]	Daily On-Peak Delivery	$/kW-day	[4] / 270	$ -	$ -
[14]	Daily Off-Peak Delivery	$/kW-day	[4] / 365	$ -	$ -
[15]	Hourly On-Peak Delivery	$/kWh	[13] / 16	$ -	$ -
[16]	Hourly Off-Peak Delivery	$/kWh	[14] / 24	$ -	$ -

Colorado Springs Utilities
Formula Rate Workbook
Projections for Rate Year 2026

THIS SHEET IS IN USE FOR THE TRUE-UP RATE CALCULATION USING ACTUALS

Table T2

Table T2: Annual Transmission Revenue Requirement

Line No.	Item	Source/Calculation	Actual for 2024
Operating Expenses			
	Operations and Maintenance		
[1]	Transmission O&M Expense	Table E1: [A][31]	$ -
[2]	Load Dispatch	Table E1: [A][3]	$ -
[3]	Transmission by Others	Table E1: [A][15]	$ -
[4]	**Transmission O&M Less Load Dispatch and Transmission by Others**	**[1] - [2] - [3]**	**$ -**
	Administrative and General		
[5]	Total A&G Expense	Table E2: [A][15]	$ -
[6]	(Less) FERC Annual Fees	Internal Records, (Note A)	$ -
[7]	(Less) EPRI & Regulatory Commission Exp. & Non-safety Ad	Internal Records, (Note A)	$ -
[8]	Wage and Salary Allocator	Table T3: [3]	
[9]	Total A&G Expense Allocated to Transmission	SUM([5]:[7]) x [8]	$ -
[10]	Transmission Related Regulatory Commission Expense	Internal Records (Note C)	$ -
[11]	**Administrative and General Expense**	**[9] + [10]**	**$ -**
[12]	Common O&M Expense Allocated to Transmission	Internal Records, (Note B)	$ -
[13]	Transmission Lease Payments	Internal Records	$ -
[14]	**TOTAL OPERATING EXPENSES**	**[4] + [11] + [12] + [13]**	**$ -**

Colorado Springs Utilities
Formula Rate Workbook
Projections for Rate Year 2026

THIS SHEET IS IN USE FOR THE TRUE-UP RATE CALCULATION USING ACTUALS

Table T2

Table T2: Annual Transmission Revenue Requirement

Line No.	Item	Source/Calculation	Actual for 2024
Capital Projects			
	Debt Service		
[15]	Total Debt Service	Internal Records	$ -
[16]	Gross Plant Allocator - Transmission	Table T3: [9]	
[17]	**Total Debt Service Allocated to Transmission**	**[15] x [16]**	**$ -**
	Cash-Funded New Construction Assets		
[18]	Total Transmission Electric Capital	Table C1: [B][9]	$ -
[19]	Total General Electric Capital	Table C1: [D][9]	$ -
[20]	Gross Plant Allocator - Transmission	Table T3: [9]	
[21]	General Electric Capital Allocated to Transmission	[19] x [20]	$ -
[22]	Total Electric Capital Assigned and Allocated to Transmission	[18] + [21]	$ -
[23]	Cash-Funded Capital Allocator	Table T3: [20]	
[24]	**Total Cash-Funded New Construction Assets Allocated to Transmission**	[22] x [23]	$ -
	Amortization of Premium or Discount		
[25]	Amortization of Premium or Discount	Table C4: [F][51]	$ -
[26]	Gross Plant Allocator - Transmission	Table T3: [9]	
[27]	**Total Amortization of Premium or Discount Allocated to Transmission**	**[25] x [26]**	**$ -**
[28]	Interest on Commercial Paper Directly Assigned to Transmission	Internal Records, (Note D)	$ -
[29]	**TOTAL CAPITAL PROJECTS**	**[17] + [24] + [27] + [28]**	**$ -**

Colorado Springs Utilities
Formula Rate Workbook
Projections for Rate Year 2026

THIS SHEET IS IN USE FOR THE TRUE-UP RATE CALCULATION USING ACTUALS

Table T2

Table T2: Annual Transmission Revenue Requirement

Line No.	Item	Source/Calculation	Actual for 2024
Other Taxes			
	Labor-Related Taxes	(Note E)	
[30]	Payroll	Internal Records	$ -
[31]	Highway and Vehicle	Internal Records	$ -
[32]	Wage and Salary Allocator	Table T3: [3]	
[33]	**Labor-Related Taxes Allocated to Transmission**	**([30] + [31]) x [32]**	**$ -**
	Plant-Related Taxes	(Note E)	
[34]	Property	Internal Records	$ -
[35]	Gross Reciepts	Internal Records	$ -
[36]	Other	Internal Records	$ -
[37]	Gross Plant Allocator - Transmission	Table T3: [9]	
[38]	**Plant-Related Taxes Allocated to Transmission**	**SUM([34]:[36]) x [37]**	**$ -**
	Surplus Payments to the City and Franchise Fees		
[39]	Surplus Payments to the City and Franchise Fees	Internal Records, (Note F)	$ -
[40]	Net Plant Allocator	Table T3: [17]	
[41]	**Surplus Payments and Franchise Fees Allocated to Transmission**	[39] x [40]	**$ -**
[42]	**TOTAL OTHER TAXES**	**[33] + [38] + [41]**	**$ -**

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THIS SHEET IS IN USE FOR THE TRUE-UP RATE CALCULATION USING ACTUALS

Table T2

Table T2: Annual Transmission Revenue Requirement

Line No.	Item	Source/Calculation	Actual for 2024
Revenue Requirement			
	Bond Covenant Requirement	(Note G)	
[43]	Total Debt Service	[15]	$ -
[44]	Required Cash Available for Debt Service to Meet Bond Covenant	% of Debt Service	
[45]	Cash Available for Debt Service	[43] x [44]	$ -
[46]	Gross Plant Allocator - Transmission	Table T3: [9]	
[47]	**Bond Covenant Requirement Allocated to Transmission**	**[45] x [46]**	**$ -**
[48]	**TRANSMISSION REVENUE REQUIREMENT**	**[14] + [29] + [42] + [47]**	**$ -**
[49]	Revenue Credits	**Table E3: [16]**	$ -
[50]	**TRANSMISSION REVENUE REQUIREMENT NET OF REVENUE CREDITS**	**[48] - [49]**	**$ -**

Notes:

(A) EPRI Annual Membership Dues (within Account 930), All Regulatory Commission Expenses (Account 928), and non-safety related advertising (within Account 930). Source: TFR Backup, [WP2 O&M - A&G] tab

(B) Common expense includes operations and maintenance shared across Electric, Natural Gas, Water, and Wastewater Services that is allocated to transmission.

(C) Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting (within Account 928)

(D) Commercial Paper interest that can be directly assigned to Transmission operations. If commercial paper is issued on behalf of specific areas of operations then the interest expense incurred from the issuance of commercial paper for Transmission operations will be directly assigned to Transmission on this line.

(E) Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Formula Rate Template, since they are recovered elsewhere.

(F) CSU provides for surplus payments to the City in lieu of taxes, based on a fixed rate per kWh of electricity sales within the city. Franchise Fees are related to providing Electric Service to customers residing in other neighboring cities or municipalities.

(G) The utility must collect a percentage of Debt Service to meet its Bond Covenant Requirement.

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THIS SHEET IS IN USE FOR THE TRUE-UP RATE CALCULATION USING ACTUALS

Table T3

Table T3: Allocators Based on Actuals

For use in Revenue Requirement Calculation

Line No.	Item	Source/Calculation	Actual for 2024
	Labor		
[1]	Total Labor Expense	Internal Records	$ -
[2]	Transmission Labor Expense	Table E1: [B][31]	$ -
[3]	**Wage and Salary Allocator**	**[1] / [2]**	
	Plant		
[4]	Gross Plant in Service	Sum of: Table PD1, [18]	$ -
[5]	Gross Transmission Plant	Table PD1: [B][18]	$ -
[6]	General Plant	Table PD1: [D][18] + [E][18]	$ -
[7]	Wage and Salary Allocator	[3]	
[8]	General Plant Allocated to Transmission	[6] x [7]	$ -
[9]	**Gross Plant Allocator - Transmission**	**([5] + [8])/[4]**	
[10]	Accumulated Depreciation	Sum of Table PD2, [18]	$ -
[11]	Net Plant	[4] - [10]	$ -
[12]	Transmission Accumulated Depreciation	Table PD2: [B][18]	$ -
[13]	General Plant Accumulated Depreciation	Table PD2: [D][18] + [E][18]	$ -
[14]	Wage and Salary Allocator	[3]	
[15]	General Accumulated Depreciation Allocated to Transmission	[13] x [14]	$ -
[16]	Net Transmission Plant	[5] + [8] - [12] - [15]	$ -
[17]	**Net Plant Allocator**	**[16] / [11]**	
	Electric Capital		
[18]	Cash-Funded Capital Less CIAC and Adjustments	Table C1: [F][9]	$ -
[19]	Total Electric Capital Less Adjustments	Sum of Table C1: [A][9]:[D][9]	$ -
[20]	**Cash-Funded Capital Allocator**	**[18] / [19]**	

Notes:
[1] Total Labor Expense is the sum of Actual Year Budget from TFR Backup, [WP2 O&M - A&G] tab.

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THIS SHEET IS IN USE FOR THE TRUE-UP RATE CALCULATION USING ACTUALS

Table T4

Table T4: Load Divisor

MW

Line No.	Month [A]	Firm Network for Self [B]	Fountain Firm Network Service for Others [C]	Long-Term Firm Point to Point Reservations [D]	Other Long-Term Firm Service [E]	Short Term Firm Point to Point Reservation [F]	Transmission System Peak Load [G] SUM([B]:[F])	12-Month Coincident Peak Average [H] [G] - [F]
[1]	January	-	-	-	-	-	-	-
[2]	February	-	-	-	-	-	-	-
[3]	March	-	-	-	-	-	-	-
[4]	April	-	-	-	-	-	-	-
[5]	May	-	-	-	-	-	-	-
[6]	June	-	-	-	-	-	-	-
[7]	July	-	-	-	-	-	-	-
[8]	August	-	-	-	-	-	-	-
[9]	September	-	-	-	-	-	-	-
[10]	October	-	-	-	-	-	-	-
[11]	November	-	-	-	-	-	-	-
[12]	December	-	-	-	-	-	-	-
[13]	12-Month Total							-
[14]	12-Month CP Average							-
[15]	**12-Month CP Average (kW)**							**-**

Notes:
[H]: 12-month CP average includes all load with the exception of Short-Term Firm Point-to-Point load.
[13]: SUM([1]:[12]).
[14]: [13]/ 12.
[15]: [14] x 1000.

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THIS SHEET IS IN USE FOR THE PROJECTED RATE CALCULATION

Table P1

Table P1: Projected Annual Transmission Revenue Requirement

Line No.	Item	Source/Calculation	Projected for 2026
Operating Expenses			
	Operations and Maintenance		
[1]	Transmission O&M Expense	Table E1: [C][31]	$ -
[2]	Load Dispatch	Table E1: [C][3]	$ -
[3]	Transmission by Others	Table E1: [C][15]	$ -
[4]	**Transmission O&M Less Load Dispatch and Transmission by Others**	**[1] - [2] - [3]**	**$ -**
	Administrative and General		
[5]	Total A&G Expense	Table E2: [B][15]	$ -
[6]	(Less) FERC Annual Fees	Internal Records, (Note A)	$ -
[7]	(Less) EPRI & Regulatory Commission Exp. & Non-safety Ad	Internal Records, (Note A)	$ -
[8]	Wage and Salary Allocator	Table P2: [3]	
[9]	Total A&G Expense Allocated to Transmission	SUM([5]:[7]) x [8]	$ -
[10]	Transmission Related Regulatory Commission Expense	Internal Records (Note C)	$ -
[11]	**Administrative and General Expense**	**[9] + [10]**	**$ -**
[12]	Common O&M Expense Allocated to Transmission	Internal Records, (Note B)	$ -
[13]	Transmission Lease Payments	Internal Records	$ -
[14]	**TOTAL OPERATING EXPENSES**	**[4] + [11] + [12] + [13]**	**$ -**

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THIS SHEET IS IN USE FOR THE PROJECTED RATE CALCULATION

Table P1

Table P1: Projected Annual Transmission Revenue Requirement

Line No.	Item	Source/Calculation	Projected for 2026
Capital Projects			
	Debt Service		
[15]	Total Debt Service	Table C3: [G][52] x 1000	$ -
[16]	Gross Plant Allocator - Transmission	Table P2: [9]	
[17]	**Total Debt Service Allocated to Transmission**	**[15] x [16]**	**$ -**
	Cash-Funded New Construction Assets		
[18]	Projected Transmission Capital Additions	Table P4: [B][9]	$ -
[19]	Projected General Capital Additions	Table P4: [D][9]	$ -
[20]	Gross Plant Allocator - Transmission	Table P2: [9]	
[21]	General Electric Capital Allocated to Transmission	[19] x [20]	$ -
[22]	Total Electric Capital Assigned and Allocated to Transmission	[18] + [21]	$ -
[23]	Cash-Funded Capital Allocator	Table P2: [20]	
[24]	**Total Cash-Funded New Construction Assets Allocated to Transmission**	**[22] x [23]**	**$ -**
	Amortization of Premium or Discount		
[25]	Amortization of Premium or Discount	Table C4: [F][51]	$ -
[26]	Gross Plant Allocator - Transmission	Table P2: [9]	
[27]	**Total Amortization of Premium or Discount Allocated to Transmission**	**[25] x [26]**	**$ -**
[28]	Interest on Commercial Paper Directly Assigned to Transmission	Internal Records, (Note D)	$ -
[29]	**TOTAL CAPITAL PROJECTS**	**[17] + [24] + [27] + [28]**	**$ -**

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THIS SHEET IS IN USE FOR THE PROJECTED RATE CALCULATION

Table P1

Table P1: Projected Annual Transmission Revenue Requirement

Line No.	Item	Source/Calculation	Projected for 2026
Other Taxes			
	Labor-Related Taxes	(Note E)	
[30]	Payroll	Internal Records	$ -
[31]	Highway and Vehicle	Internal Records	$ -
[32]	Wage and Salary Allocator	Table P2: [3]	
[33]	**Labor-Related Taxes Allocated to Transmission**	**([30] + [31]) x [32]**	**$ -**
	Plant-Related Taxes	(Note E)	
[34]	Property	Internal Records	$ -
[35]	Gross Reciepts	Internal Records	$ -
[36]	Other	Internal Records	$ -
[37]	Gross Plant Allocator - Transmission	Table P2: [9]	
[38]	**Plant-Related Taxes Allocated to Transmission**	**SUM([34]:[36]) x [37]**	**$ -**
	Surplus Payments to the City and Franchise Fees		
[39]	Surplus Payments to the City and Franchise Fees	Internal Records, (Note F)	$ -
[40]	Net Plant Allocator	Table P2: [17]	
[41]	**Surplus Payments and Franchise Fees Allocated to Transmission**	[39] x [40]	**$ -**
[42]	**TOTAL OTHER TAXES**	**[33] + [38] + [41]**	**$ -**

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THIS SHEET IS IN USE FOR THE PROJECTED RATE CALCULATION

Table P1

Table P1: Projected Annual Transmission Revenue Requirement

Line No.	Item	Source/Calculation	Projected for 2026
Revenue Requirement			
	Bond Covenant Requirement	(Note G)	
[43]	Total Debt Service	[15]	$ -
[44]	Required Cash Available for Debt Service to Meet Bond Covenant	% of Debt Service	
[45]	Cash Available for Debt Service	[43] x [44]	$ -
[46]	Gross Plant Allocator - Transmission	Table P2: [9]	
[47]	**Bond Covenant Requirement Allocated to Transmission**	**[45] x [46]**	**$ -**
[48]	**TRANSMISSION REVENUE REQUIREMENT**	**[14] + [29] + [42] + [47]**	**$ -**
[49]	Revenue Credits	**Table E3: [16]**	$ -
[50]	**TRANSMISSION REVENUE REQUIREMENT NET OF REVENUE CREDITS**	**[48] - [49]**	**$ -**

Notes:

(A) EPRI Annual Membership Dues (within Account 930), All Regulatory Commission Expenses (Account 928), and non-safety related advertising (within Account 930). Source: TFR Backup, [WP2 O&M - A&G] tab

(B) Common expense includes operations and maintenance shared across Electric, Natural Gas, Water, and Wastewater Services that is allocated to transmission.

(C) Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting (within Account 928)

(D) Commercial Paper interest that can be directly assigned to Transmission operations. If commercial paper is issued on behalf of specific areas of operations then the interest expense incurred from the issuance of commercial paper for Transmission operations will be directly assigned to Transmission on this line.

(E) Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Formula Rate Template, since they are recovered elsewhere.

(F) CSU provides for surplus payments to the City in lieu of taxes, based on a fixed rate per kWh of electricity sales within the city. Franchise Fees are related to providing Electric Service to customers residing in other neighboring cities or municipalities.

(G) The utility must collect a percentage of Debt Service to meet its Bond Covenant Requirement.

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THIS SHEET IS IN USE FOR THE PROJECTED RATE CALCULATION

Table P2

Table P2: Allocators Based on Projections

For use in Revenue Requirement Calculation

Line No.	Item	Source/Calculation	Projected for 2026
	Labor		
[1]	Total Labor Expense	Internal Records	$ -
[2]	Transmission Labor Expense	Table E1: [D][31]	$ -
[3]	**Wage and Salary Allocator**	**[1] / [2]**	
	Plant		
[4]	Gross Plant in Service	Sum of: Table P4, [11]	$ -
[5]	Gross Transmission Plant	Table P4: [B][11]	$ -
[6]	General and Intangible Plant	Table P4: [D][11] + [E][11]	$ -
[7]	Wage and Salary Allocator	[3]	
[8]	General and Intangible Plant Allocated to Transmission	[6] x [7]	$ -
[9]	**Gross Plant Allocator - Transmission**	**([5] + [8])/[4]**	
[10]	Accumulated Depreciation	Sum of Table PD2, [18]	$ -
[11]	Net Plant	[4] - [10]	$ -
[12]	Transmission Accumulated Depreciation	Table PD2: [B][18]	$ -
[13]	General and Intangible Accumulated Depreciation	Table PD2: [D][18] + [E][18]	$ -
[14]	Wage and Salary Allocator	[3]	
[15]	General and Intangible Accumulated Depreciation Allocated to Transmission	[13] x [14]	$ -
[16]	Net Transmission Plant	[5] + [8] - [12] - [15]	$ -
[17]	**Net Plant Allocator**	**[16]/[11]**	
	Electric Capital		
[18]	Cash-Funded Capital Less CIAC and Adjustments	Table C1: [F][9]	$ -
[19]	Total Electric Capital Less Adjustments	Sum of Table C1: [A][9]:[D][9]	$ -
[20]	**Cash-Funded Capital Allocator**	**[18] / [19]**	

Notes:
[1] Total Labor Expense is the sum of Projected Year Budget from TFR Backup, [WP2 O&M - A&G] tab.

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THIS SHEET IS IN USE FOR THE PROJECTED RATE CALCULATION

Table P3

Table P3: True Up

Projected ATRR Only

Line No.	Item	Source/Calculation		Total
[1]	Year for True-Up:			2024
[2]	**Revenue**			
[3]	2024 Actual ATRR	Table T2: [50]	$	-
[4]	2024 Revenue Collected	Internal Records		
[5]	**Undercollection / (Refund)**	[3] - [4]	$	-
[6]	**Prior Period Adjustment (if Necessary)**	Supplemental Workpaper	$	-
[7]	**True-Up Before Interest**	[5] + [6]	$	-
	Interest Rates			
[8]	Q3 2024	FERC Posted Interest Rates		
[9]	Q4 2024	FERC Posted Interest Rates		
[10]	Q1 2025	FERC Posted Interest Rates		
[11]	Q2 2025	FERC Posted Interest Rates		
[12]	**Average**	([8] + [9] + [10] + [11])/4		0.00%
[13]	**True-Up Interest**	[6] x (([12]/12 months) x 24 months)	$	-
[14]	**Total True-Up**	[7] + [13]	$	-

Notes:
[4]: Collected on Formula Rate Submitted in 2023. Disclaimer: With 2026 anticipated to be the first year of implementing a formula rate, 2024 revenues collected are assumed to equal the 2024 Actual ATRR calculated in this workbook.

Prior Period Adjustment, if any, is calculated to the same timing basis as balance of true up (i.e. before interest applied on lines 15 and 22). Work-papers for the Prior Period Adjustment calculation will be included in supporting documentation. CSU will only use the Prior Period Adjustment in the following circumstances and only if the error discovered would have impacted CSU's calculation of the True-Up Amount in a prior Rate Year: (1) CSU discovers a error in a previously filed formula rate (filed outside the current Rate Year), (2) discovers an error in books and records actually used to populate an input in the formula rate and the discovery is outside the current Rate Year, or (3) CSU is required by applicable law, a court or regulatory body to correct an error outside the current Rate Year. If an error falls within one of these three categories and negatively impacted customers in CSU's calculation of a prior Rate Year’s True-Up Amount, CSU will re-calculate the True-Up Amount for affected years.

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THIS SHEET IS IN USE FOR THE PROJECTED RATE CALCULATION

Table P4

Table P4: Projected Plant Additions

Line No.	Month	Source/Calculation	Production Plant [A]	Transmission Plant [B]	Distribution Plant [C]	General Plant [D]	Intangible Plant [E]
[1]	Projected Additions		$ -	$ -	$ -	$ -	$ -
[2]	Adjustments						
[3]			$ -	$ -	$ -	$ -	$ -
[4]			$ -	$ -	$ -	$ -	$ -
[5]			$ -	$ -	$ -	$ -	$ -
[6]			$ -	$ -	$ -	$ -	$ -
[7]			$ -	$ -	$ -	$ -	$ -
[8]			$ -	$ -	$ -	$ -	$ -
[9]	**Total Adjusted Projected Additions**	**SUM([1]:[8])**	$ -	$ -	$ -	$ -	$ -
[10]	**December 2024 Gross Plant**	Table PD1: [18]	$ -	$ -	$ -	$ -	$ -
[11]	**2026 Average Gross Plant**	[10] + ([9] / 2)	$ -	$ -	$ -	$ -	$ -

Notes:
[11]: Average Gross Plant additions are calculated as half of projected additions assuming plant is placed in service evenly throughout the year.

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THIS SHEET IS IN USE FOR THE PROJECTED RATE CALCULATION

Table P5

Table P5: Projected Load

MW

Line No.	Month	Firm Network for Self [A]	Fountain Firm Network Service for Others [B]	Long-Term Firm Point to Point Reservations [C]	Other Long-Term Firm Service [D]	Short Term Firm Point to Point Reservation [E]	Transmission System Peak Load [F] SUM([A]:[E])	12-Month Coincident Peak Average [G] [F] - [E]
[1]	January	-	-	-	-	-	-	-
[2]	February	-	-	-	-	-	-	-
[3]	March	-	-	-	-	-	-	-
[4]	April	-	-	-	-	-	-	-
[5]	May	-	-	-	-	-	-	-
[6]	June	-	-	-	-	-	-	-
[7]	July	-	-	-	-	-	-	-
[8]	August	-	-	-	-	-	-	-
[9]	September	-	-	-	-	-	-	-
[10]	October	-	-	-	-	-	-	-
[11]	November	-	-	-	-	-	-	-
[12]	December	-	-	-	-	-	-	-
[13]	12-Month Total							-
[14]	12-Month CP Average							-
[15]	**12-Month CP Average (kW)**							**-**

Notes:
[G]: 12-month CP average includes all load with the exception of Short-Term Firm Point-to-Point load.
[13]: SUM([1]:[12]).
[14]: [13]/ 12.
[15]: [14] x 1000.

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Table PD1

Table PD1: Gross Plant

Line No.	Month	Production Plant [A]	Transmission Plant [B]	Distribution Plant [C]
[1]	Dec-23	$ -	$ -	$ -
[2]	Jan-24	$ -	$ -	$ -
[3]	Feb-24	$ -	$ -	$ -
[4]	Mar-24	$ -	$ -	$ -
[5]	Apr-24	$ -	$ -	$ -
[6]	May-24	$ -	$ -	$ -
[7]	Jun-24	$ -	$ -	$ -
[8]	Jul-24	$ -	$ -	$ -
[9]	Aug-24	$ -	$ -	$ -
[10]	Sep-24	$ -	$ -	$ -
[11]	Oct-24	$ -	$ -	$ -
[12]	Nov-24	$ -	$ -	$ -
[13]	Dec-24	$ -	$ -	$ -
[14]	**Average Balance**	$ -	$ -	$ -
[15]	13 Month Average: Plant not Included in Rate Base *(enter negative)*	$ -	$ -	$ -
[16]		$ -	$ -	$ -
[17]		$ -	$ -	$ -
[18]	**Average Rate Base Balance**	$ -	$ -	$ -

Source: CSU Electric Plant Asset Book Value Workbook, summarized in TFR Backup, [WP3 Elec Plant Summary] tab

Notes:

[15] 13-Month Average Gross Plant of plant not included in rate base is entered as the average over the December prior to the Actuals Rate Year and each month of the Actuals Rate Year

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Table PD1

Table PD1: Gross Plant

Line No.	Month	General Plant [D]	Intangible Plant [E]
[1]	Dec-23	$ -	$ -
[2]	Jan-24	$ -	$ -
[3]	Feb-24	$ -	$ -
[4]	Mar-24	$ -	$ -
[5]	Apr-24	$ -	$ -
[6]	May-24	$ -	$ -
[7]	Jun-24	$ -	$ -
[8]	Jul-24	$ -	$ -
[9]	Aug-24	$ -	$ -
[10]	Sep-24	$ -	$ -
[11]	Oct-24	$ -	$ -
[12]	Nov-24	$ -	$ -
[13]	Dec-24	$ -	$ -
[14]	**Average Balance**	$ -	$ -
[15]	13 Month Average: Plant not Included in Rate Base *(enter negative)*	$ -	$ -
[16]		$ -	$ -
[17]		$ -	$ -
[18]	**Average Rate Base Balance**	$ -	$ -

Source: CSU Electric Plant Asset Book Value Workbook, summarized in TFR Backup, [WP3 Elec Plant Summary] tab

Notes:

[15] 13-Month Average Gross Plant of plant not included in rate base is entered as the average over the December prior to the Actuals Rate Year and each month of the Actuals Rate Year

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Table PD2

Table PD2: Accumulated Depreciation

Line No.	Month	Production Plant [A]	Transmission Plant [B]	Distribution Plant [C]
[1]	Dec-23	$ -	$ -	$ -
[2]	Jan-24	$ -	$ -	$ -
[3]	Feb-24	$ -	$ -	$ -
[4]	Mar-24	$ -	$ -	$ -
[5]	Apr-24	$ -	$ -	$ -
[6]	May-24	$ -	$ -	$ -
[7]	Jun-24	$ -	$ -	$ -
[8]	Jul-24	$ -	$ -	$ -
[9]	Aug-24	$ -	$ -	$ -
[10]	Sep-24	$ -	$ -	$ -
[11]	Oct-24	$ -	$ -	$ -
[12]	Nov-24	$ -	$ -	$ -
[13]	Dec-24	$ -	$ -	$ -
[14]	**Average Balance**	$ -	$ -	$ -
[15]	13 Month Average: Plant not Included in Rate Base *(enter negative)*	$ -	$ -	$ -
[16]		$ -	$ -	$ -
[17]		$ -	$ -	$ -
[18]	**Average Rate Base Balance**	$ -	$ -	$ -

Source: CSU Electric Plant Asset Book Value Workbook, summarized in TFR Backup, [WP3 Elec Plant Summary] tab

Notes:

[15] 13-Month Average Accumulated Depreciation of plant not included in rate base is entered as the average over the December prior to the Actuals Rate Year and each month of the Actuals Rate Year

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Table PD2

Table PD2: Accumulated Depreciation

Line No.	Month	General Plant [D]	Intangible Plant [E]
[1]	Dec-23	$ -	$ -
[2]	Jan-24	$ -	$ -
[3]	Feb-24	$ -	$ -
[4]	Mar-24	$ -	$ -
[5]	Apr-24	$ -	$ -
[6]	May-24	$ -	$ -
[7]	Jun-24	$ -	$ -
[8]	Jul-24	$ -	$ -
[9]	Aug-24	$ -	$ -
[10]	Sep-24	$ -	$ -
[11]	Oct-24	$ -	$ -
[12]	Nov-24	$ -	$ -
[13]	Dec-24	$ -	$ -
[14]	**Average Balance**	$ -	$ -
[15]	13 Month Average: Plant not Included in Rate Base *(enter negative)*	$ -	$ -
[16]		$ -	$ -
[17]		$ -	$ -
[18]	**Average Rate Base Balance**	$ -	$ -

Source: CSU Electric Plant Asset Book Value Workbook, summarized in TFR Backup, [WP3 Elec Plant Summary] tab

Notes:

[15] 13-Month Average Accumulated Depreciation of plant not included in rate base is entered as the average over the December prior to the Actuals Rate Year and each month of the Actuals Rate Year

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THIS SHEET IS IN USE FOR THE TRUE-UP RATE CALCULATION USING ACTUALS

Table C1

Table C1: Electric Capital Summary

Line No.	Item	Source/Calculation	Production Plant [A]	Transmission Plant [B]	Distribution Plant [C]	General Plant [D]	Intangible Plant [E]	Cash-Funded Capital Less CIAC [F]
[1]	**Total Electric Capital**	Table C2	$ -	$ -	$ -	$ -	$ -	$ -
[2]	**Adjustments**							
[3]			$ -	$ -	$ -	$ -	$ -	$ -
[4]			$ -	$ -	$ -	$ -	$ -	$ -
[5]			$ -	$ -	$ -	$ -	$ -	$ -
[6]			$ -	$ -	$ -	$ -	$ -	$ -
[7]			$ -	$ -	$ -	$ -	$ -	$ -
[8]			$ -	$ -	$ -	$ -	$ -	$ -
[9]	**Total Adjusted Electric Capital**	**SUM([1]:[8])**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

Notes: Adjustments to Total Electric Capital for exclusion of plant not recovered in rates and inclusion of shared assets from common plant.

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THIS SHEET IS IN USE FOR THE TRUE-UP RATE CALCULATION USING ACTUALS

Table C2

Table C2: Electric Capital Detail

Line No.	Project Name [A]	Electric Capital [B]	Assigned Function [C]
[1]			
[2]			
[3]			
[4]			
[5]			
[6]			
[7]			
[8]			
[9]			
[10]			
[11]	**Total Electric Capital by Project**	$ -	
[12]	Cash-Funded Electric Capital		Internal Records
[13]	Allocated Electric Capital		Internal Records

Sources and Notes: [12] Cash-Funded Electric Capital is sourced from Internal record and is allocated to Transmission and General Plant. [13] Allocated Electric Capital is sourced from internal records and allocated to General Plant in the Electric Capital Summary tab. TFR Backup, [WP11 Misc Support] tab contains extracts from internal systems for source support.

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Table C3

Table C3: Debt Service and Interest

Thousands ($000)

Line No.	Bond Issue [A]	Electric Percentage [B]	Total Principal [C]	Total Interest [D]	Electric Principal [E] [C] x [B]	Electric Interest [F] [D] x [B]	Total Electric Debt [G] [E] + [F]
[1]		0.0%	$ -	$ -	$ -	$ -	$ -
[2]		0.0%	$ -	$ -	$ -	$ -	$ -
[3]		0.0%	$ -	$ -	$ -	$ -	$ -
[4]		0.0%	$ -	$ -	$ -	$ -	$ -
[5]		0.0%	$ -	$ -	$ -	$ -	$ -
[6]		0.0%	$ -	$ -	$ -	$ -	$ -
[7]		0.0%	$ -	$ -	$ -	$ -	$ -
[8]		0.0%	$ -	$ -	$ -	$ -	$ -
[9]		0.0%	$ -	$ -	$ -	$ -	$ -
[10]		0.0%	$ -	$ -	$ -	$ -	$ -
[11]		0.0%	$ -	$ -	$ -	$ -	$ -
[12]		0.0%	$ -	$ -	$ -	$ -	$ -
[13]		0.0%	$ -	$ -	$ -	$ -	$ -
[14]		0.0%	$ -	$ -	$ -	$ -	$ -
[15]		0.0%	$ -	$ -	$ -	$ -	$ -
[16]		0.0%	$ -	$ -	$ -	$ -	$ -
[17]		0.0%	$ -	$ -	$ -	$ -	$ -
[18]		0.0%	$ -	$ -	$ -	$ -	$ -
[19]		0.0%	$ -	$ -	$ -	$ -	$ -
[20]		0.0%	$ -	$ -	$ -	$ -	$ -
[21]		0.0%	$ -	$ -	$ -	$ -	$ -
[22]		0.0%	$ -	$ -	$ -	$ -	$ -
[23]		0.0%	$ -	$ -	$ -	$ -	$ -

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Table C3

Table C3: Debt Service and Interest

Thousands ($000)

Line No.	Bond Issue [A]	Electric Percentage [B]	Total Principal [C]	Total Interest [D]	Electric Principal [E] [C] x [B]	Electric Interest [F] [D] x [B]	Total Electric Debt [G] [E] + [F]
[24]		0.0%	$ -	$ -	$ -	$ -	$ -
[25]		0.0%	$ -	$ -	$ -	$ -	$ -
[26]		0.0%	$ -	$ -	$ -	$ -	$ -
[27]		0.0%	$ -	$ -	$ -	$ -	$ -
[28]		0.0%	$ -	$ -	$ -	$ -	$ -
[29]		0.0%	$ -	$ -	$ -	$ -	$ -
[30]		0.0%	$ -	$ -	$ -	$ -	$ -
[31]		0.0%	$ -	$ -	$ -	$ -	$ -
[32]		0.0%	$ -	$ -	$ -	$ -	$ -
[33]		0.0%	$ -	$ -	$ -	$ -	$ -
[34]		0.0%	$ -	$ -	$ -	$ -	$ -
[35]		0.0%	$ -	$ -	$ -	$ -	$ -
[36]		0.0%	$ -	$ -	$ -	$ -	$ -
[37]		0.0%	$ -	$ -	$ -	$ -	$ -
[38]		0.0%	$ -	$ -	$ -	$ -	$ -
[39]		0.0%	$ -	$ -	$ -	$ -	$ -
[40]		0.0%	$ -	$ -	$ -	$ -	$ -
[41]		0.0%	$ -	$ -	$ -	$ -	$ -
[42]		0.0%	$ -	$ -	$ -	$ -	$ -
[43]		0.0%	$ -	$ -	$ -	$ -	$ -
[44]		0.0%	$ -	$ -	$ -	$ -	$ -
[45]		0.0%	$ -	$ -	$ -	$ -	$ -
[46]		0.0%	$ -	$ -	$ -	$ -	$ -

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Table C3

Table C3: Debt Service and Interest

Thousands ($000)

Line No.	Bond Issue [A]	Electric Percentage [B]	Total Principal [C]	Total Interest [D]	Electric Principal [E] [C] x [B]	Electric Interest [F] [D] x [B]	Total Electric Debt [G] [E] + [F]
[47]		0.0%	$ -	$ -	$ -	$ -	$ -
[48]		0.0%	$ -	$ -	$ -	$ -	$ -
[49]		0.0%	$ -	$ -	$ -	$ -	$ -
[50]		0.0%	$ -	$ -	$ -	$ -	$ -
[51]	Forecasted Debt		$ -	$ -	$ -	$ -	$ -
[52]	**Total**		$ -	$ -	$ -	$ -	$ -

Source: TFR Backup, [WP7 Debt Service and Interest] tab.

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Table C4

Table C4: Amortization of Premium or Discount

Line No.	Fiscal Year [A]	Account Number [B]	Account Name [C]	Sub Account [D]	Sub Account Cost Type [E]	Balance Year-To-Date [F]
[1]						
[2]						
[3]						
[4]						
[5]						
[6]						
[7]						
[8]						
[9]						
[10]						
[11]						
[12]						
[13]						
[14]						
[15]						
[16]						
[17]						
[18]						
[19]						
[20]						
[21]						
[22]						
[23]						
[24]						
[25]						
[26]						
[27]						
[28]						
[29]						

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Table C4

Table C4: Amortization of Premium or Discount

Line No.	Fiscal Year [A]	Account Number [B]	Account Name [C]	Sub Account [D]	Sub Account Cost Type [E]	Balance Year-To-Date [F]
[30]						
[31]						
[32]						
[33]						
[34]						
[35]						
[36]						
[37]						
[38]						
[39]						
[40]						
[41]						
[42]						
[43]						
[51]	**Total Amortization of Premium or Discount**					$ -

Source: TFR Backup, [WP8 Amortization of prem or dis] & [WP9 Bond Issu Amort Exp Detail] tabs.

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Table E1

Table E1: Transmission Operations and Maintenance (O&M) Expenses

Line No.	Item	FERC Account No./Calculation	Actual Total [A]	Actual Labor-Related [B]
[1]	**Operation**			
[2]	Operation, Supervision and Engineering	560	$ -	$ -
[3]	Load Dispatching	561	$ -	$ -
[4]	Load Dispatch- Reliability	561.1	$ -	$ -
[5]	Load Dispatch- Monitor and Operate Transmission System	561.2	$ -	$ -
[6]	Load Dispatch- Transmission Service and Scheduling	561.3	$ -	$ -
[7]	Scheduling, System Control and Dispatch Services	561.4	$ -	$ -
[8]	Reliability, Planning and Standards Development	561.5	$ -	$ -
[9]	Transmission Service Studies	561.6	$ -	$ -
[10]	Generation Interconnection Studies	561.7	$ -	$ -
[11]	Reliability, Planning and Standards Development Services	561.8	$ -	$ -
[12]	Station Expenses	562	$ -	$ -
[13]	Overhead Line Expenses	563	$ -	$ -
[14]	Underground Line Expenses	564	$ -	$ -
[15]	Transmission of Electricity by Others	565	$ -	$ -
[16]	Miscellaneous Transmission Expenses	566	$ -	$ -
[17]	Rents	567	$ -	$ -
[18]	**Total Operation**		$ -	$ -

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Table E1

Table E1: Transmission Operations and Maintenance (O&M) Expenses

Line No.	Item	FERC Account No./Calculation	Actual Total [A]	Actual Labor-Related [B]
[19]	**Maintenance**			
[20]	Maintenance Supervision and Engineering	568	$ -	$ -
[21]	Maintenance of Structures	569	$ -	$ -
[22]	Maintenance of Computer Hardware	569.1	$ -	$ -
[23]	Maintenance of Computer Software	569.2	$ -	$ -
[24]	Maintenance of Communication Equipment	569.3	$ -	$ -
[25]	Maintenance of Miscellaneous Regional Transmission Plant	569.4	$ -	$ -
[26]	Maintenance of Station Equipment	570	$ -	$ -
[27]	Maintenance of Overhead Lines	571	$ -	$ -
[28]	Maintenance of Underground Lines	572	$ -	$ -
[29]	Maintenance of Miscellaneous Transmission Plant	573	$ -	$ -
[30]	**Total Maintenance**		$ -	$ -
[31]	**Total Operation and Maintenance Expense**	**[18] + [30]**	**$ -**	**$ -**

Source: TFR Backup, [WP2 O&M - A&G] tab.

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Table E1

Table E1: Transmission Operations and Maintenance (O&M) Expenses

Line No.	Item	FERC Account No./Calculation	Projected Total [C]	Projected Labor-Related [D]
[1]	**Operation**			
[2]	Operation, Supervision and Engineering	560	$ -	$ -
[3]	Load Dispatching	561	$ -	$ -
[4]	Load Dispatch- Reliability	561.1	$ -	$ -
[5]	Load Dispatch- Monitor and Operate Transmission System	561.2	$ -	$ -
[6]	Load Dispatch- Transmission Service and Scheduling	561.3	$ -	$ -
[7]	Scheduling, System Control and Dispatch Services	561.4	$ -	$ -
[8]	Reliability, Planning and Standards Development	561.5	$ -	$ -
[9]	Transmission Service Studies	561.6	$ -	$ -
[10]	Generation Interconnection Studies	561.7	$ -	$ -
[11]	Reliability, Planning and Standards Development Services	561.8	$ -	$ -
[12]	Station Expenses	562	$ -	$ -
[13]	Overhead Line Expenses	563	$ -	$ -
[14]	Underground Line Expenses	564	$ -	$ -
[15]	Transmission of Electricity by Others	565	$ -	$ -
[16]	Miscellaneous Transmission Expenses	566	$ -	$ -
[17]	Rents	567	$ -	$ -
[18]	**Total Operation**		$ -	$ -

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Table E1

Table E1: Transmission Operations and Maintenance (O&M) Expenses

Line No.	Item	FERC Account No./Calculation	Projected Total [C]	Projected Labor-Related [D]
[19]	**Maintenance**			
[20]	Maintenance Supervision and Engineering	568	$ -	$ -
[21]	Maintenance of Structures	569	$ -	$ -
[22]	Maintenance of Computer Hardware	569.1	$ -	$ -
[23]	Maintenance of Computer Software	569.2	$ -	$ -
[24]	Maintenance of Communication Equipment	569.3	$ -	$ -
[25]	Maintenance of Miscellaneous Regional Transmission Plant	569.4	$ -	$ -
[26]	Maintenance of Station Equipment	570	$ -	$ -
[27]	Maintenance of Overhead Lines	571	$ -	$ -
[28]	Maintenance of Underground Lines	572	$ -	$ -
[29]	Maintenance of Miscellaneous Transmission Plant	573	$ -	$ -
[30]	**Total Maintenance**		$ -	$ -
[31]	**Total Operation and Maintenance Expense**	**[18] + [30]**	**$ -**	**$ -**

Source: TFR Backup, [WP2 O&M - A&G] tab.

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Table E2

Table E2: Administrative and General (A&G) Expenses

Line No.	Item	FERC Account No.	Actual Account Balance [A]	Projected Account Balance [B]
[1]	Administrative and General Salaries	920	$ -	$ -
[2]	Office Supplies and Expenses	921	$ -	$ -
[3]	Administrative Expenses Transferred-Credit (*enter negative*)	922	$ -	$ -
[4]	Outside Services Employed	923	$ -	$ -
[5]	Property Insurance	924	$ -	$ -
[6]	Injuries and Damage	925	$ -	$ -
[7]	Employee Pensions and Benefits	926	$ -	$ -
[8]	Franchise Requirements	927	$ -	$ -
[9]	Regulatory Commission Expenses	928	$ -	$ -
[10]	Duplicate Charges - Credit (*enter negative*)	929	$ -	$ -
[11]	General Advertising Expenses	930.1	$ -	$ -
[12]	Miscellaneous General Expenses	930.2	$ -	$ -
[13]	Rents	931	$ -	$ -
[14]	Maintenance of General Plant	932	$ -	$ -
[15]	**Total Administrative and General Expense**		$ -	$ -

Source: TFR Backup, [WP2 O&M - A&G] tab.

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Table E3

Table E3: Revenue Credits

Line No.	Item	Source/Calculation	FERC Account No.	Total Transmission
	Sales for Resale			
[1]	Bundled Non-RQ Sales for Resale		447	$ -
[2]	Bundled Sales for Resale included in Divisor		447	$ -
[3]	**Total Sales for Resale**	**[1] + [2]**		$ -
	Rent from Electric Property			
[4]			454	$ -
[5]			454	$ -
[6]			454	$ -
[7]			454	$ -
[8]			454	$ -
[9]			454	$ -
[10]			454	$ -
[11]			454	$ -
[12]			454	$ -
[13]			454	$ -
[14]	**Total Rent from Electric Property**	**SUM([4]:[13])**		$ -
[15]	**Other Electric Revenues Credited**	**Table E4: [15]**	456	$ -
[16]	**TOTAL REVENUE CREDITS**	**[3] + [14] + [15]**		$ -

Source: TFR Backup, [WP10 Account 456.1] tab.

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Table E4

Table E4: Other Electric Revenues

Line No.	Description	Assignment	Total Revenue
[1]	Firm Network	Divisor	$ -
[2]	Long Term Firm	Divisor	$ -
[3]	Other Long Term Firm	Divisor	$ -
[4]	Short Term Firm Point To Point	Credit	$ -
[5]	Non Firm	Credit	$ -
[6]	Other Service	Divisor	$ -
[7]	Distribution Wheeling Fees (Direct)	Divisor	$ -
[8]	Non-Firm Off-System Revenues	Credit	$ -
[9]	Schedule 4 - Energy Imbalance Service	Divisor	$ -
[10]			$ -
[11]			$ -
[12]			$ -
[13]			$ -
[14]			$ -
[15]	**TOTAL REVENUE CREDIT**		$ -

Source: TFR Backup, [WP10 Account 456.1] tab.

Transmission Owner Filing

Formula Rate Tables

Populated

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Table T1

Table T1: Transmission Rate Calculation

Projections for Rate Year 2026

Line No.	Item	Unit	Source/Calculation	Actual	Projected
[1]	Transmission Revenue Requirement Net of Revenue Credits	$/year	Table T2 or Table P1: [50]	$ 50,814,334	$ 34,281,960
[2]	True-Up (if Applicable)	$/year	Table P3: [14]	n/a	$ -
[3]	Peak Transmission Load	kW	Table T4: [15] or Table P5: [15]	834,170	888,917
	Schedule 7: Long-Term Firm and Short-Term Point-to-Point Transmission Service				
	The charges are as follows:				
[4]	Yearly Delivery	$/kW-year	([1] + [2]) / [3]	$ 60.92	$ 38.57
[5]	Monthly Delivery	$/kW-month	[4] / 12	$ 5.0763	$ 3.2138
[6]	Weekly Delivery	$/kW-week	[4] / 52	$ 1.1715	$ 0.7417
[7]	Daily On-Peak Delivery	$/kW-day	[4] / 270	$ 0.2256	$ 0.1428
[8]	Daily Off-Peak Delivery	$/kW-day	[4] / 365	$ 0.1669	$ 0.1057
[9]	Hourly On-Peak Delivery	$/kWh	[7] / 16	$ 0.0141	$ 0.0089
[10]	Hourly Off-Peak Delivery	$/kWh	[8] / 24	$ 0.0070	$ 0.0044
	Schedule 8: Non-Firm Point-to-Point Transmission Service				
	The charges can be up to the following limits:				
[11]	Monthly Delivery	$/kW-month	[4] / 12	$ 5.0763	$ 3.2138
[12]	Weekly Delivery	$/kW-week	[4] / 52	$ 1.1715	$ 0.7417
[13]	Daily On-Peak Delivery	$/kW-day	[4] / 270	$ 0.2256	$ 0.1428
[14]	Daily Off-Peak Delivery	$/kW-day	[4] / 365	$ 0.1669	$ 0.1057
[15]	Hourly On-Peak Delivery	$/kWh	[13] / 16	$ 0.0141	$ 0.0089
[16]	Hourly Off-Peak Delivery	$/kWh	[14] / 24	$ 0.0070	$ 0.0044

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THIS SHEET IS IN USE FOR THE TRUE-UP RATE CALCULATION USING ACTUALS

Table T2

Table T2: Annual Transmission Revenue Requirement

Line No.	Item	Source/Calculation		Actual for 2024
Operating Expenses				
	Operations and Maintenance			
[1]	Transmission O&M Expense	Table E1: [A][31]	$	6,655,735
[2]	Load Dispatch	Table E1: [A][3]	$	769,735
[3]	Transmission by Others	Table E1: [A][15]	$	-
[4]	**Transmission O&M Less Load Dispatch and Transmission by Others**	**[1] - [2] - [3]**	**$**	**5,886,000**
	Administrative and General			
[5]	Total A&G Expense	Table E2: [A][15]	$	74,972,938
[6]	(Less) FERC Annual Fees	Internal Records, (Note A)	$	-
[7]	(Less) EPRI & Regulatory Commission Exp. & Non-safety Ad	Internal Records, (Note A)	$	-
[8]	Wage and Salary Allocator	Table T3: [3]		10.4%
[9]	Total A&G Expense Allocated to Transmission	SUM([5]:[7]) x [8]	$	7,775,582
[10]	Transmission Related Regulatory Commission Expense	Internal Records (Note C)	$	-
[11]	**Administrative and General Expense**	**[9] + [10]**	**$**	**7,775,582**
[12]	Common O&M Expense Allocated to Transmission	Internal Records, (Note B)	$	-
[13]	Transmission Lease Payments	Internal Records	$	-
[14]	**TOTAL OPERATING EXPENSES**	**[4] + [11] + [12] + [13]**	**$**	**13,661,582**

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THIS SHEET IS IN USE FOR THE TRUE-UP RATE CALCULATION USING ACTUALS

Table T2

Table T2: Annual Transmission Revenue Requirement

Line No.	Item	Source/Calculation		Actual for 2024
Capital Projects				
	Debt Service			
[15]	Total Debt Service	Internal Records	$	85,551,954
[16]	Gross Plant Allocator - Transmission	Table T3: [9]		8.6%
[17]	**Total Debt Service Allocated to Transmission**	**[15] x [16]**	**$**	**7,340,806**
	Cash-Funded New Construction Assets			
[18]	Total Transmission Electric Capital	Table C1: [B][9]	$	65,364,327
[19]	Total General Electric Capital	Table C1: [D][9]	$	49,130,893
[20]	Gross Plant Allocator - Transmission	Table T3: [9]		8.6%
[21]	General Electric Capital Allocated to Transmission	[19] x [20]	$	4,215,688
[22]	Total Electric Capital Assigned and Allocated to Transmission	[18] + [21]	$	69,580,015
[23]	Cash-Funded Capital Allocator	Table T3: [20]		37.2%
[24]	**Total Cash-Funded New Construction Assets Allocated to Transmission**	[22] x [23]	$	25,874,269
	Amortization of Premium or Discount			
[25]	Amortization of Premium or Discount	Table C4: [F][51]	$	(6,274,637)
[26]	Gross Plant Allocator - Transmission	Table T3: [9]		8.6%
[27]	**Total Amortization of Premium or Discount Allocated to Transmission**	**[25] x [26]**	**$**	**(538,397)**
[28]	Interest on Commercial Paper Directly Assigned to Transmission	Internal Records, (Note D)	$	-
[29]	**TOTAL CAPITAL PROJECTS**	**[17] + [24] + [27] + [28]**	**$**	**32,676,679**

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THIS SHEET IS IN USE FOR THE TRUE-UP RATE CALCULATION USING ACTUALS

Table T2

Table T2: Annual Transmission Revenue Requirement

Line No.	Item	Source/Calculation	Actual for 2024
Other Taxes			
	Labor-Related Taxes	(Note E)	
[30]	Payroll	Internal Records	$ -
[31]	Highway and Vehicle	Internal Records	$ -
[32]	Wage and Salary Allocator	Table T3: [3]	10.37%
[33]	**Labor-Related Taxes Allocated to Transmission**	**([30] + [31]) x [32]**	**$ -**
	Plant-Related Taxes	(Note E)	
[34]	Property	Internal Records	$ -
[35]	Gross Reciepts	Internal Records	$ -
[36]	Other	Internal Records	$ -
[37]	Gross Plant Allocator - Transmission	Table T3: [9]	8.58%
[38]	**Plant-Related Taxes Allocated to Transmission**	**SUM([34]:[36]) x [37]**	**$ -**
	Surplus Payments to the City and Franchise Fees		
[39]	Surplus Payments to the City and Franchise Fees	Internal Records, (Note F)	$ 25,349,433
[40]	Net Plant Allocator	Table T3: [17]	9.0%
[41]	**Surplus Payments and Franchise Fees Allocated to Transmission**	[39] x [40]	**$ 2,273,831**
[42]	**TOTAL OTHER TAXES**	**[33] + [38] + [41]**	**$ 2,273,831**

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THIS SHEET IS IN USE FOR THE TRUE-UP RATE CALCULATION USING ACTUALS

Table T2

Table T2: Annual Transmission Revenue Requirement

Line No.	Item	Source/Calculation		Actual for 2024
Revenue Requirement				
	Bond Covenant Requirement	(Note G)		
[43]	Total Debt Service	[15]	$	85,551,954
[44]	Required Cash Available for Debt Service to Meet Bond Covenant	% of Debt Service		30%
[45]	Cash Available for Debt Service	[43] x [44]	$	25,665,586
[46]	Gross Plant Allocator - Transmission	Table T3: [9]		8.6%
[47]	**Bond Covenant Requirement Allocated to Transmission**	**[45] x [46]**	**$**	**2,202,242**
[48]	**TRANSMISSION REVENUE REQUIREMENT**	**[14] + [29] + [42] + [47]**	**$**	**50,814,334**
[49]	Revenue Credits	**Table E3: [16]**	$	-
[50]	**TRANSMISSION REVENUE REQUIREMENT NET OF REVENUE CREDITS**	**[48] - [49]**	**$**	**50,814,334**

Notes:

(A) EPRI Annual Membership Dues (within Account 930), All Regulatory Commission Expenses (Account 928), and non-safety related advertising (within Account 930). Source: TFR Backup, [WP2 O&M - A&G] tab

(B) Common expense includes operations and maintenance shared across Electric, Natural Gas, Water, and Wastewater Services that is allocated to transmission.

(C) Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting (within Account 928)

(D) Commercial Paper interest that can be directly assigned to Transmission operations. If commercial paper is issued on behalf of specific areas of operations then the interest expense incurred from the issuance of commercial paper for Transmission operations will be directly assigned to Transmission on this line.

(E) Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Formula Rate Template, since they are recovered elsewhere.

(F) CSU provides for surplus payments to the City in lieu of taxes, based on a fixed rate per kWh of electricity sales within the city. Franchise Fees are related to providing Electric Service to customers residing in other neighboring cities or municipalities.

(G) The utility must collect a percentage of Debt Service to meet its Bond Covenant Requirement.

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THIS SHEET IS IN USE FOR THE TRUE-UP RATE CALCULATION USING ACTUALS

Table T3

Table T3: Allocators Based on Actuals

For use in Revenue Requirement Calculation

Line No.	Item	Source/Calculation	Actual for 2024
	Labor		
[1]	Total Labor Expense	Internal Records	$ 56,214,252
[2]	Transmission Labor Expense	Table E1: [B][31]	$ 5,830,084
[3]	**Wage and Salary Allocator**	**[1] / [2]**	**10.37%**
	Plant		
[4]	Gross Plant in Service	Sum of: Table PD1, [18]	$ 2,586,365,838
[5]	Gross Transmission Plant	Table PD1: [B][18]	$ 204,880,933
[6]	General Plant	Table PD1: [D][18] + [E][18]	$ 164,328,527
[7]	Wage and Salary Allocator	[3]	10.37%
[8]	General Plant Allocated to Transmission	[6] x [7]	$ 17,042,816
[9]	**Gross Plant Allocator - Transmission**	**([5] + [8])/[4]**	**8.58%**
[10]	Accumulated Depreciation	Sum of Table PD2, [18]	$ 1,540,750,617
[11]	Net Plant	[4] - [10]	$ 1,045,615,221
[12]	Transmission Accumulated Depreciation	Table PD2: [B][18]	$ 117,452,418
[13]	General Plant Accumulated Depreciation	Table PD2: [D][18] + [E][18]	$ 102,979,329
[14]	Wage and Salary Allocator	[3]	10.37%
[15]	General Accumulated Depreciation Allocated to Transmission	[13] x [14]	$ 10,680,177
[16]	Net Transmission Plant	[5] + [8] - [12] - [15]	$ 93,791,154
[17]	**Net Plant Allocator**	**[16] / [11]**	**8.97%**
	Electric Capital		
[18]	Cash-Funded Capital Less CIAC and Adjustments	Table C1: [F][9]	$ 76,512,765
[19]	Total Electric Capital Less Adjustments	Sum of Table C1: [A][9]:[D][9]	$ 205,754,964
[20]	**Cash-Funded Capital Allocator**	**[18] / [19]**	**37.19%**

Notes:
[1] Total Labor Expense is the sum of Actual Year Budget from TFR Backup, [WP2 O&M - A&G] tab.

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THIS SHEET IS IN USE FOR THE TRUE-UP RATE CALCULATION USING ACTUALS

Table T4

Table T4: Load Divisor

MW

Line No.	Month [A]	Firm Network for Self [B]	Fountain Firm Network Service for Others [C]	Long-Term Firm Point to Point Reservations [D]	Other Long-Term Firm Service [E]	Short Term Firm Point to Point Reservation [F]	Transmission System Peak Load [G] SUM([B]:[F])	12-Month Coincident Peak Average [H] [G] - [F]
[1]	January	844	43	-	-	40	927	887
[2]	February	685	34	-	-	-	719	719
[3]	March	663	32	-	-	10	706	696
[4]	April	618	30	-	-	-	649	649
[5]	May	658	39	-	-	-	697	697
[6]	June	978	60	-	-	23	1,062	1,039
[7]	July	1,011	65	-	-	24	1,099	1,075
[8]	August	993	64	-	-	27	1,084	1,057
[9]	September	834	51	-	-	20	905	885
[10]	October	752	47	-	-	-	799	799
[11]	November	705	33	-	-	-	738	738
[12]	December	733	38	-	-	-	771	771
[13]	12-Month Total							10,010
[14]	12-Month CP Average							834
[15]	**12-Month CP Average (kW)**							**834,170**

Notes:
[H]: 12-month CP average includes all load with the exception of Short-Term Firm Point-to-Point load.
[13]: SUM([1]:[12]).
[14]: [13]/ 12.
[15]: [14] x 1000.

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THIS SHEET IS IN USE FOR THE PROJECTED RATE CALCULATION

Table P1

Table P1: Projected Annual Transmission Revenue Requirement

Line No.	Item	Source/Calculation		Projected for 2026
Operating Expenses				
	Operations and Maintenance			
[1]	Transmission O&M Expense	Table E1: [C][31]	$	9,646,593
[2]	Load Dispatch	Table E1: [C][3]	$	2,255,582
[3]	Transmission by Others	Table E1: [C][15]	$	-
[4]	**Transmission O&M Less Load Dispatch and Transmission by Others**	**[1] - [2] - [3]**	**$**	**7,391,011**
	Administrative and General			
[5]	Total A&G Expense	Table E2: [B][15]	$	84,847,133
[6]	(Less) FERC Annual Fees	Internal Records, (Note A)	$	-
[7]	(Less) EPRI & Regulatory Commission Exp. & Non-safety Ad	Internal Records, (Note A)	$	-
[8]	Wage and Salary Allocator	Table P2: [3]		11.5%
[9]	Total A&G Expense Allocated to Transmission	SUM([5]:[7]) x [8]	$	9,761,229
[10]	Transmission Related Regulatory Commission Expense	Internal Records (Note C)	$	-
[11]	**Administrative and General Expense**	**[9] + [10]**	**$**	**9,761,229**
[12]	Common O&M Expense Allocated to Transmission	Internal Records, (Note B)	$	-
[13]	Transmission Lease Payments	Internal Records	$	-
[14]	**TOTAL OPERATING EXPENSES**	**[4] + [11] + [12] + [13]**	**$**	**17,152,240**

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THIS SHEET IS IN USE FOR THE PROJECTED RATE CALCULATION

Table P1

Table P1: Projected Annual Transmission Revenue Requirement

Line No.	Item	Source/Calculation		Projected for 2026
Capital Projects				
	Debt Service			
[15]	Total Debt Service	Table C3: [G][52] x 1000	$	125,372,167
[16]	Gross Plant Allocator - Transmission	Table P2: [9]		8.5%
[17]	**Total Debt Service Allocated to Transmission**	**[15] x [16]**	**$**	**10,711,016**
	Cash-Funded New Construction Assets			
[18]	Projected Transmission Capital Additions	Table P4: [B][9]	$	2,270,703
[19]	Projected General Capital Additions	Table P4: [D][9]	$	16,421,360
[20]	Gross Plant Allocator - Transmission	Table P2: [9]		8.5%
[21]	General Electric Capital Allocated to Transmission	[19] x [20]	$	1,402,939
[22]	Total Electric Capital Assigned and Allocated to Transmission	[18] + [21]	$	3,673,642
[23]	Cash-Funded Capital Allocator	Table P2: [20]		37.2%
[24]	**Total Cash-Funded New Construction Assets Allocated to Transmission**	**[22] x [23]**	**$**	**1,366,093**
	Amortization of Premium or Discount			
[25]	Amortization of Premium or Discount	Table C4: [F][51]	$	(6,274,637)
[26]	Gross Plant Allocator - Transmission	Table P2: [9]		8.5%
[27]	**Total Amortization of Premium or Discount Allocated to Transmission**	**[25] x [26]**	**$**	**(536,066)**
[28]	Interest on Commercial Paper Directly Assigned to Transmission	Internal Records, (Note D)	$	-
[29]	**TOTAL CAPITAL PROJECTS**	**[17] + [24] + [27] + [28]**	**$**	**11,541,044**

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THIS SHEET IS IN USE FOR THE PROJECTED RATE CALCULATION

Table P1

Table P1: Projected Annual Transmission Revenue Requirement

Line No.	Item	Source/Calculation	Projected for 2026
Other Taxes			
	Labor-Related Taxes	(Note E)	
[30]	Payroll	Internal Records	$ -
[31]	Highway and Vehicle	Internal Records	$ -
[32]	Wage and Salary Allocator	Table P2: [3]	11.5%
[33]	**Labor-Related Taxes Allocated to Transmission**	**([30] + [31]) x [32]**	**$ -**
	Plant-Related Taxes	(Note E)	
[34]	Property	Internal Records	$ -
[35]	Gross Reciepts	Internal Records	$ -
[36]	Other	Internal Records	$ -
[37]	Gross Plant Allocator - Transmission	Table P2: [9]	8.5%
[38]	**Plant-Related Taxes Allocated to Transmission**	**SUM([34]:[36]) x [37]**	**$ -**
	Surplus Payments to the City and Franchise Fees		
[39]	Surplus Payments to the City and Franchise Fees	Internal Records, (Note F)	$ 27,132,089
[40]	Net Plant Allocator	Table P2: [17]	8.8%
[41]	**Surplus Payments and Franchise Fees Allocated to Transmission**	[39] x [40]	**$ 2,375,371**
[42]	**TOTAL OTHER TAXES**	**[33] + [38] + [41]**	**$ 2,375,371**

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THIS SHEET IS IN USE FOR THE PROJECTED RATE CALCULATION

Table P1

Table P1: Projected Annual Transmission Revenue Requirement

Line No.	Item	Source/Calculation		Projected for 2026
Revenue Requirement				
	Bond Covenant Requirement	(Note G)		
[43]	Total Debt Service	[15]	$	125,372,167
[44]	Required Cash Available for Debt Service to Meet Bond Covenant	% of Debt Service		30%
[45]	Cash Available for Debt Service	[43] x [44]	$	37,611,650
[46]	Gross Plant Allocator - Transmission	Table P2: [9]		8.5%
[47]	**Bond Covenant Requirement Allocated to Transmission**	**[45] x [46]**	**$**	**3,213,305**
[48]	**TRANSMISSION REVENUE REQUIREMENT**	**[14] + [29] + [42] + [47]**	**$**	**34,281,960**
[49]	Revenue Credits	**Table E3: [16]**	$	-
[50]	**TRANSMISSION REVENUE REQUIREMENT NET OF REVENUE CREDITS**	**[48] - [49]**	**$**	**34,281,960**

Notes:

(A) EPRI Annual Membership Dues (within Account 930), All Regulatory Commission Expenses (Account 928), and non-safety related advertising (within Account 930). Source: TFR Backup, [WP2 O&M - A&G] tab

(B) Common expense includes operations and maintenance shared across Electric, Natural Gas, Water, and Wastewater Services that is allocated to transmission.

(C) Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting (within Account 928)

(D) Commercial Paper interest that can be directly assigned to Transmission operations. If commercial paper is issued on behalf of specific areas of operations then the interest expense incurred from the issuance of commercial paper for Transmission operations will be directly assigned to Transmission on this line.

(E) Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Formula Rate Template, since they are recovered elsewhere.

(F) CSU provides for surplus payments to the City in lieu of taxes, based on a fixed rate per kWh of electricity sales within the city. Franchise Fees are related to providing Electric Service to customers residing in other neighboring cities or municipalities.

(G) The utility must collect a percentage of Debt Service to meet its Bond Covenant Requirement.

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THIS SHEET IS IN USE FOR THE PROJECTED RATE CALCULATION

Table P2

Table P2: Allocators Based on Projections

For use in Revenue Requirement Calculation

Line No.	Item	Source/Calculation	Projected for 2026
	Labor		
[1]	Total Labor Expense	Internal Records	$ 63,336,555
[2]	Transmission Labor Expense	Table E1: [D][31]	$ 7,286,547
[3]	**Wage and Salary Allocator**	**[1] / [2]**	**11.50%**
	Plant		
[4]	Gross Plant in Service	Sum of: Table P4, [11]	$ 2,643,756,154
[5]	Gross Transmission Plant	Table P4: [B][11]	$ 206,016,285
[6]	General and Intangible Plant	Table P4: [D][11] + [E][11]	$ 172,539,207
[7]	Wage and Salary Allocator	[3]	11.5%
[8]	General and Intangible Plant Allocated to Transmission	[6] x [7]	$ 19,849,754
[9]	**Gross Plant Allocator - Transmission**	**([5] + [8])/[4]**	**8.54%**
[10]	Accumulated Depreciation	Sum of Table PD2, [18]	$ 1,540,750,617
[11]	Net Plant	[4] - [10]	$ 1,103,005,537
[12]	Transmission Accumulated Depreciation	Table PD2: [B][18]	$ 117,452,418
[13]	General and Intangible Accumulated Depreciation	Table PD2: [D][18] + [E][18]	$ 102,979,329
[14]	Wage and Salary Allocator	[3]	11.5%
[15]	General and Intangible Accumulated Depreciation Allocated to Transmission	[13] x [14]	$ 11,847,246
[16]	Net Transmission Plant	[5] + [8] - [12] - [15]	$ 96,566,375
[17]	**Net Plant Allocator**	**[16]/[11]**	**8.75%**
	Electric Capital		
[18]	Cash-Funded Capital Less CIAC and Adjustments	Table C1: [F][9]	$ 76,512,765
[19]	Total Electric Capital Less Adjustments	Sum of Table C1: [A][9]:[D][9]	$ 205,754,964
[20]	**Cash-Funded Capital Allocator**	**[18] / [19]**	**37.19%**

Notes:
[1] Total Labor Expense is the sum of Projected Year Budget from TFR Backup, [WP2 O&M - A&G] tab.

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THIS SHEET IS IN USE FOR THE PROJECTED RATE CALCULATION

Table P3

Table P3: True Up

Projected ATRR Only

Line No.	Item	Source/Calculation	Total
[1]	Year for True-Up:		2024
[2]	**Revenue**		
[3]	2024 Actual ATRR	Table T2: [50]	$ 50,814,334
[4]	2024 Revenue Collected	Internal Records	$ 50,814,334
[5]	**Undercollection / (Refund)**	[3] - [4]	$ -
[6]	**Prior Period Adjustment (if Necessary)**	Supplemental Workpaper	$ -
[7]	**True-Up Before Interest**	[5] + [6]	$ -
	Interest Rates		
[8]	Q3 2024	FERC Posted Interest Rates	8.50%
[9]	Q4 2024	FERC Posted Interest Rates	8.50%
[10]	Q1 2025	FERC Posted Interest Rates	8.04%
[11]	Q2 2025	FERC Posted Interest Rates	7.55%
[12]	**Average**	([8] + [9] + [10] + [11])/4	8.15%
[13]	**True-Up Interest**	[6] x (([12]/12 months) x 24 months)	$ -
[14]	**Total True-Up**	[7] + [13]	$ -

Notes:

[4]: Collected on Formula Rate Submitted in 2023. Disclaimer: No Formula Rate was submitted in 2023. With 2026 anticipated to be the first year of implementing a formula rate, 2024 revenues collected are assumed to equal the 2024 Actual ATRR calculated in this workbook.

Prior Period Adjustment, if any, is calculated to the same timing basis as balance of true up (i.e. before interest applied on lines 15 and 22). Work-papers for the Prior Period Adjustment calculation will be included in supporting documentation. CSU will only use the Prior Period Adjustment in the following circumstances and only if the error discovered would have impacted CSU's calculation of the True-Up Amount in a prior Rate Year: (1) CSU discovers a error in a previously filed formula rate (filed outside the current Rate Year), (2) discovers an error in books and records actually used to populate an input in the formula rate and the discovery is outside the current Rate Year, or (3) CSU is required by applicable law, a court or regulatory body to correct an error outside the current Rate Year. If an error falls within one of these three categories and negatively impacted customers in CSU's calculation of a prior Rate Year’s True-Up Amount, CSU will re-calculate the True-Up Amount for affected years.

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THIS SHEET IS IN USE FOR THE PROJECTED RATE CALCULATION

Table P4

Table P4: Projected Plant Additions

Line No.	Month	Source/Calculation	Production Plant [A]	Transmission Plant [B]	Distribution Plant [C]	General Plant [D]	Intangible Plant [E]
[1]	Projected Additions	Internal Records	$ 65,830,494	$ 2,270,703	$ 30,258,075	$ 86,055,794	$ -
[2]	Adjustments						
[3]	193952 - Operational Fiber Network	Internal Records	$ -	$ -	$ -	$ (77,823,614)	$ -
[4]	Allocated Electric Capital	Internal Records	$ -	$ -	$ -	$ 8,189,180	$ -
[5]			$ -	$ -	$ -	$ -	$ -
[6]			$ -	$ -	$ -	$ -	$ -
[7]			$ -	$ -	$ -	$ -	$ -
[8]			$ -	$ -	$ -	$ -	$ -
[9]	**Total Adjusted Projected Additions**	**SUM([1]:[8])**	$ 65,830,494	$ 2,270,703	$ 30,258,075	$ 16,421,360	$ -
[10]	**December 2024 Gross Plant**	Table PD1: [18]	$ 922,017,956	$ 204,880,933	$ 1,295,138,422	$ 164,328,527	$ -
[11]	**2026 Average Gross Plant**	[10] + ([9] / 2)	$ 954,933,203	$ 206,016,285	$ 1,310,267,459	$ 172,539,207	$ -

Notes:
[11]: Average Gross Plant additions are calculated as half of projected additions assuming plant is placed in service evenly throughout the year.

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THIS SHEET IS IN USE FOR THE PROJECTED RATE CALCULATION

Table P5

Table P5: Projected Load

MW

Line No.	Month	Firm Network for Self [A]	Fountain Firm Network Service for Others [B]	Long-Term Firm Point to Point Reservations [C]	Other Long-Term Firm Service [D]	Short Term Firm Point to Point Reservation [E]	Transmission System Peak Load [F] SUM([A]:[E])	12-Month Coincident Peak Average [G] [F] - [E]
[1]	January	894	46	-	-	-	940	940
[2]	February	767	39	-	-	-	806	806
[3]	March	744	38	-	-	-	782	782
[4]	April	699	36	-	-	-	735	735
[5]	May	729	38	-	-	-	767	767
[6]	June	1,037	61	-	-	-	1,098	1,098
[7]	July	1,096	65	-	-	-	1,161	1,161
[8]	August	1,059	63	-	-	-	1,122	1,122
[9]	September	899	53	-	-	-	952	952
[10]	October	668	34	-	-	-	702	702
[11]	November	742	38	-	-	-	780	780
[12]	December	782	40	-	-	-	822	822
[13]	12-Month Total							10,667
[14]	12-Month CP Average							889
[15]	**12-Month CP Average (kW)**							**888,917**

Notes:
[G]: 12-month CP average includes all load with the exception of Short-Term Firm Point-to-Point load.
[13]: SUM([1]:[12]).
[14]: [13]/ 12.
[15]: [14] x 1000.

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Table PD1

Table PD1: Gross Plant

Line No.	Month	Production Plant [A]	Transmission Plant [B]	Distribution Plant [C]
[1]	Dec-23	$ 919,118,601	$ 193,622,468	$ 1,285,343,980
[2]	Jan-24	$ 919,118,601	$ 193,622,468	$ 1,285,343,980
[3]	Feb-24	$ 919,118,601	$ 193,622,468	$ 1,285,343,980
[4]	Mar-24	$ 919,118,601	$ 193,622,468	$ 1,285,343,980
[5]	Apr-24	$ 919,118,601	$ 193,622,468	$ 1,285,343,980
[6]	May-24	$ 919,120,339	$ 193,622,468	$ 1,285,874,066
[7]	Jun-24	$ 919,120,339	$ 196,326,482	$ 1,287,721,282
[8]	Jul-24	$ 919,120,339	$ 196,326,482	$ 1,287,721,282
[9]	Aug-24	$ 919,120,339	$ 196,326,482	$ 1,287,721,282
[10]	Sep-24	$ 919,120,339	$ 196,326,482	$ 1,287,721,282
[11]	Oct-24	$ 928,605,799	$ 201,416,697	$ 1,306,154,063
[12]	Nov-24	$ 931,332,799	$ 256,007,897	$ 1,306,544,129
[13]	Dec-24	$ 935,100,132	$ 258,986,795	$ 1,360,622,194
[14]	**Average Balance**	$ 922,017,956	$ 204,880,933	$ 1,295,138,422
[15]	13 Month Average: Plant not Included in Rate Base *(enter negative)*	$ -	$ -	$ -
[16]		$ -	$ -	$ -
[17]		$ -	$ -	$ -
[18]	**Average Rate Base Balance**	$ 922,017,956	$ 204,880,933	$ 1,295,138,422

Source: CSU Electric Plant Asset Book Value Workbook, summarized in TFR Backup, [WP3 Elec Plant Summary] tab

Notes:

[15] 13-Month Average Gross Plant of plant not included in rate base is entered as the average over the December prior to the Actuals Rate Year and each month of the Actuals Rate Year

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Table PD1

Table PD1: Gross Plant

Line No.	Month	General Plant [D]	Intangible Plant [E]
[1]	Dec-23	$ 161,227,902	$ -
[2]	Jan-24	$ 161,227,902	$ -
[3]	Feb-24	$ 161,169,863	$ -
[4]	Mar-24	$ 161,744,051	$ -
[5]	Apr-24	$ 161,681,566	$ -
[6]	May-24	$ 161,182,189	$ -
[7]	Jun-24	$ 162,306,706	$ -
[8]	Jul-24	$ 159,658,355	$ -
[9]	Aug-24	$ 159,633,595	$ -
[10]	Sep-24	$ 159,592,684	$ -
[11]	Oct-24	$ 161,232,635	$ -
[12]	Nov-24	$ 162,108,363	$ -
[13]	Dec-24	$ 203,505,042	$ -
[14]	**Average Balance**	$ 164,328,527	$ -
[15]	13 Month Average: Plant not Included in Rate Base *(enter negative)*	$ -	$ -
[16]		$ -	$ -
[17]		$ -	$ -
[18]	**Average Rate Base Balance**	$ 164,328,527	$ -

Source: CSU Electric Plant Asset Book Value Workbook, summarized in TFR Backup, [WP3 Elec Plant Summary] tab

Notes:

[15] 13-Month Average Gross Plant of plant not included in rate base is entered as the average over the December prior to the Actuals Rate Year and each month of the Actuals Rate Year

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Table PD2

Table PD2: Accumulated Depreciation

Line No.	Month	Production Plant [A]	Transmission Plant [B]	Distribution Plant [C]
[1]	Dec-23	$ 520,431,632	$ 115,023,017	$ 760,162,249
[2]	Jan-24	$ 524,041,838	$ 115,392,758	$ 763,159,824
[3]	Feb-24	$ 527,652,042	$ 115,762,499	$ 766,157,397
[4]	Mar-24	$ 531,262,250	$ 116,132,241	$ 769,154,974
[5]	Apr-24	$ 534,871,676	$ 116,501,982	$ 772,152,545
[6]	May-24	$ 538,481,144	$ 116,871,725	$ 775,162,717
[7]	Jun-24	$ 542,101,341	$ 117,345,198	$ 778,199,780
[8]	Jul-24	$ 545,696,052	$ 117,707,450	$ 781,135,741
[9]	Aug-24	$ 549,290,075	$ 118,069,702	$ 784,071,703
[10]	Sep-24	$ 552,883,155	$ 118,431,954	$ 787,007,664
[11]	Oct-24	$ 556,846,673	$ 118,885,893	$ 790,299,098
[12]	Nov-24	$ 560,635,597	$ 120,103,397	$ 793,290,136
[13]	Dec-24	$ 563,705,928	$ 120,653,614	$ 796,292,085
[14]	**Average Balance**	$ 542,146,108	$ 117,452,418	$ 778,172,763
[15]	13 Month Average: Plant not Included in Rate Base *(enter negative)*	$ -	$ -	$ -
[16]		$ -	$ -	$ -
[17]		$ -	$ -	$ -
[18]	**Average Rate Base Balance**	$ 542,146,108	$ 117,452,418	$ 778,172,763

Source: CSU Electric Plant Asset Book Value Workbook, summarized in TFR Backup, [WP3 Elec Plant Summary] tab

Notes:

[15] 13-Month Average Accumulated Depreciation of plant not included in rate base is entered as the average over the December prior to the Actuals Rate Year and each month of the Actuals Rate Year

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Table PD2

Table PD2: Accumulated Depreciation

Line No.	Month	General Plant [D]	Intangible Plant [E]
[1]	Dec-23	$ 101,336,805	$ -
[2]	Jan-24	$ 101,901,295	$ -
[3]	Feb-24	$ 102,396,983	$ -
[4]	Mar-24	$ 102,936,715	$ -
[5]	Apr-24	$ 103,423,182	$ -
[6]	May-24	$ 103,471,921	$ -
[7]	Jun-24	$ 104,024,950	$ -
[8]	Jul-24	$ 101,942,505	$ -
[9]	Aug-24	$ 102,483,535	$ -
[10]	Sep-24	$ 102,998,663	$ -
[11]	Oct-24	$ 103,365,464	$ -
[12]	Nov-24	$ 103,985,199	$ -
[13]	Dec-24	$ 104,464,060	$ -
[14]	**Average Balance**	$ 102,979,329	$ -
[15]	13 Month Average: Plant not Included in Rate Base *(enter negative)*	$ -	$ -
[16]		$ -	$ -
[17]		$ -	$ -
[18]	**Average Rate Base Balance**	$ 102,979,329	$ -

Source: CSU Electric Plant Asset Book Value Workbook, summarized in TFR Backup, [WP3 Elec Plant Summary] tab

Notes:

[15] 13-Month Average Accumulated Depreciation of plant not included in rate base is entered as the average over the December prior to the Actuals Rate Year and each month of the Actuals Rate Year

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THIS SHEET IS IN USE FOR THE TRUE-UP RATE CALCULATION USING ACTUALS

Table C1

Table C1: Electric Capital Summary

Line No.	Item	Source/Calculation	Production Plant [A]	Transmission Plant [B]	Distribution Plant [C]	General Plant [D]	Intangible Plant [E]	Cash-Funded Capital Less CIAC [F]
[1]	**Total Electric Capital**	Table C2	$ 15,981,531	$ 65,364,327	$ 75,278,214	$ 82,866,640	$ -	$ 117,102,264
[2]	**Adjustments**							
[3]	193952 - Operational Fiber Network	Table C2	$ -	$ -	$ -	$ (40,589,499)	$ -	$ (40,589,499)
[4]	Allocated Electric Capital	Internal Records	$ -	$ -	$ -	$ 6,853,752	$ -	$ -
[5]			$ -	$ -	$ -	$ -	$ -	$ -
[6]			$ -	$ -	$ -	$ -	$ -	$ -
[7]			$ -	$ -	$ -	$ -	$ -	$ -
[8]			$ -	$ -	$ -	$ -	$ -	$ -
[9]	**Total Adjusted Electric Capital**	**SUM([1]:[8])**	**$ 15,981,531**	**$ 65,364,327**	**$ 75,278,214**	**$ 49,130,893**	**$ -**	**$ 76,512,765**

Notes: Adjustments to Total Electric Capital for exclusion of plant not recovered in rates and inclusion of shared assets from common plant.

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THIS SHEET IS IN USE FOR THE TRUE-UP RATE CALCULATION USING ACTUALS

Table C2

Table C2: Electric Capital Detail

Line No.	Project Name [A]	Electric Capital [B]	Assigned Function [C]
[1]	193952 - Operational Fiber Network	$ 40,589,499	General Plant
[2]	Production Plant	$ 15,981,531	Production Plant
[3]	Transmission Plant	$ 65,364,327	Transmission Plant
[4]	Distribution Plant	$ 75,278,214	Distribution Plant
[5]	General Plant	$ 42,277,141	General Plant
[6]	Intangible Plant	$ -	Intangible Plant
[7]			
[8]			
[9]			
[10]			
[11]	**Total Electric Capital by Project**	$ 239,490,711	
[12]	Cash-Funded Electric Capital	$ 117,102,264	Internal Records
[13]	Allocated Electric Capital	$ 6,853,752	Internal Records

Sources and Notes: [12] Cash-Funded Electric Capital is sourced from Internal record and is allocated to Transmission and General Plant. [13] Allocated Electric Capital is sourced from internal records and allocated to General Plant in the Electric Capital Summary tab. TFR Backup, [WP11 Misc Support] tab contains extracts from internal systems for source support.

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Table C3

Table C3: Debt Service and Interest

Thousands ($000)

Line No.	Bond Issue [A]	Electric Percentage [B]	Total Principal [C]	Total Interest [D]	Electric Principal [E] [C] x [B]	Electric Interest [F] [D] x [B]	Total Electric Debt [G] [E] + [F]
[1]	2005A	29.1%	$ 4,375	$ 2,577	$ 1,273	$ 750	$ 2,023
[2]	2006B	3.2%	$ 3,150	$ 1,864	$ 100	$ 59	$ 159
[3]	2007A	25.8%	$ 2,890	$ 1,349	$ 746	$ 348	$ 1,094
[4]	2008A	49.8%	$ 1,730	$ 1,270	$ 861	$ 632	$ 1,493
[5]	2009B	16.6%	$ 2,800	$ 2,733	$ 464	$ 453	$ 917
[6]	2009C	72.6%	$ 1,100	$ 2,841	$ 799	$ 2,063	$ 2,862
[7]	2009D	0.0%	$ 1,205	$ 2,878	$ -	$ -	$ -
[8]	2009E	0.0%	$ 488	$ 61	$ -	$ -	$ -
[9]	2010C	61.8%	$ 1,605	$ 1,246	$ 993	$ 771	$ 1,763
[10]	2010D	100.0%	$ -	$ 7,095	$ -	$ 7,095	$ 7,095
[11]	2012A	62.4%	$ 1,540	$ 1,356	$ 961	$ 847	$ 1,808
[12]	2012B	13.6%	$ -	$ -	$ -	$ -	$ -
[13]	2012C	0.0%	$ -	$ -	$ -	$ -	$ -
[14]	2013A	19.3%	$ -	$ -	$ -	$ -	$ -
[15]	2013B1	0.0%	$ -	$ -	$ -	$ -	$ -
[16]	2013B2	0.0%	$ -	$ -	$ -	$ -	$ -
[17]	2014A1	0.0%	$ -	$ -	$ -	$ -	$ -
[18]	2014A2	0.0%	$ -	$ -	$ -	$ -	$ -
[19]	2015A	24.5%	$ 1,925	$ 2,233	$ 472	$ 548	$ 1,020
[20]	2017A1	69.4%	$ 4,380	$ 3,162	$ 3,039	$ 2,194	$ 5,233
[21]	2017A2	12.5%	$ 2,010	$ 3,586	$ 251	$ 448	$ 699
[22]	2017A3	0.0%	$ -	$ -	$ -	$ -	$ -
[23]	CP Series A	0.0%	$ -	$ -	$ -	$ -	$ -

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Table C3

Table C3: Debt Service and Interest

Thousands ($000)

Line No.	Bond Issue [A]	Electric Percentage [B]	Total Principal [C]	Total Interest [D]	Electric Principal [E] [C] x [B]	Electric Interest [F] [D] x [B]	Total Electric Debt [G] [E] + [F]
[24]	CP Series B	0.0%	$ -	$ -	$ -	$ -	$ -
[25]	2018A1	46.9%	$ 22,435	$ 1,122	$ 10,531	$ 527	$ 11,058
[26]	2018A2	0.0%	$ 910	$ 1,655	$ -	$ -	$ -
[27]	2018A3	36.6%	$ 400	$ 124	$ 146	$ 45	$ 192
[28]	2018A4	0.0%	$ 1,315	$ 2,390	$ -	$ -	$ -
[29]	2019A	31.1%	$ -	$ 4,205	$ -	$ 1,308	$ 1,308
[30]	2020A	11.1%	$ 9,310	$ 6,789	$ 1,037	$ 756	$ 1,793
[31]	2020B	99.8%	$ 6,810	$ 1,010	$ 6,795	$ 1,007	$ 7,802
[32]	2020C	45.9%	$ 755	$ 3,361	$ 346	$ 1,541	$ 1,887
[33]	2021A	49.3%	$ 2,400	$ 1,097	$ 1,183	$ 541	$ 1,724
[34]	2021B	62.4%	$ 3,490	$ 7,313	$ 2,178	$ 4,563	$ 6,741
[35]	2022A	27.4%	$ 3,650	$ 5,190	$ 1,001	$ 1,423	$ 2,424
[36]	2022B	58.3%	$ -	$ 8,140	$ -	$ 4,746	$ 4,746
[37]	2023A	51.9%	$ -	$ 10,347	$ -	$ 5,374	$ 5,374
[38]	2023B	21.9%	$ 9,580	$ 7,806	$ 2,097	$ 1,708	$ 3,805
[39]	2024A	52.8%	$ -	$ 14,674	$ -	$ 7,748	$ 7,748
[40]	2024B	11.4%	$ 13,545	$ 4,328	$ 1,550	$ 495	$ 2,046
[41]			$ -	$ -	$ -	$ -	$ -
[42]			$ -	$ -	$ -	$ -	$ -
[43]			$ -	$ -	$ -	$ -	$ -
[44]			$ -	$ -	$ -	$ -	$ -
[45]			$ -	$ -	$ -	$ -	$ -
[46]			$ -	$ -	$ -	$ -	$ -

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Table C3

Table C3: Debt Service and Interest

Thousands ($000)

Line No.	Bond Issue [A]	Electric Percentage [B]	Total Principal [C]	Total Interest [D]	Electric Principal [E] [C] x [B]	Electric Interest [F] [D] x [B]	Total Electric Debt [G] [E] + [F]
[47]			$ -	$ -	$ -	$ -	$ -
[48]			$ -	$ -	$ -	$ -	$ -
[49]			$ -	$ -	$ -	$ -	$ -
[50]			$ -	$ -	$ -	$ -	$ -
[51]	Forecasted Debt		$ -	$ -	$ -	$ -	$ 40,556
[52]	**Total**		$ 103,798	$ 113,800	$ 36,824	$ 47,992	$ 125,372

Source: TFR Backup, [WP7 Debt Service and Interest] tab.

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Table C4

Table C4: Amortization of Premium or Discount

Line No.	Fiscal Year [A]	Account Number [B]	Account Name [C]	Sub Account [D]	Sub Account Cost Type [E]	Balance Year-To-Date [F]
[1]	2026	428000	Amort of Debt Disc & Exp	90	MISCELLANEOUS ACCOUNTING GENERAL	$ 625,917
[2]	2026	428010	Amort of Discount	1027	Amort of Discount -2005A	$ 954
[3]	2026	428010	Amort of Discount	1034	Amort of Discount -2006B	$ 88
[4]	2026	428010	Amort of Discount	1050	Amort of Discount -2010D	$ 3,050
[5]	2026	428100	Amort of Loss on Reacq Debt	1036	2007B Amort Loss on Reac Debt	$ 52,358
[6]	2026	428100	Amort of Loss on Reacq Debt	1039	2008B Amort Loss on Reac Debt	$ 1,490
[7]	2026	428100	Amort of Loss on Reacq Debt	1042	2009A Amort Loss on Reac Debt	$ 23,660
[8]	2026	428100	Amort of Loss on Reacq Debt	1044	2009C Amort Loss on Reac Debt	$ 19,738
[9]	2026	428100	Amort of Loss on Reacq Debt	1047	2010A Amort Loss on Reac Debt	$ 68,399
[10]	2026	428100	Amort of Loss on Reacq Debt	1051	2011A Amort Loss on Reac Debt	$ 208,683
[11]	2026	428100	Amort of Loss on Reacq Debt	1053	2012B Amort Loss on Reac Debt	$ 32,075
[12]	2026	428100	Amort of Loss on Reacq Debt	1055	2013A Amort Loss on Reac Debt	$ 55,984
[13]	2026	428100	Amort of Loss on Reacq Debt	1066	2018A1 Amort Loss on Reac Debt	$ 913,697
[14]	2026	428100	Amort of Loss on Reacq Debt	1068	2018A3 Amort Loss on Reac Debt	$ 966
[15]	2026	429000	Amort of Prem on Debt-Cr	1043	Amort of Prem on Debt-2009B	$ (12,846)
[16]	2026	429000	Amort of Prem on Debt-Cr	1050	Amort of Prem on Debt-2010D	$ (48,193)
[17]	2026	429000	Amort of Prem on Debt-Cr	1060	Amort of Prem on Debt-2015A	$ (128,590)
[18]	2026	429000	Amort of Prem on Debt-Cr	1063	Amort of Prem on Debt-2017A-1	$ (522,217)
[19]	2026	429000	Amort of Prem on Debt-Cr	1064	Amort of Prem on Debt-2017A-2	$ (67,012)
[20]	2026	429000	Amort of Prem on Debt-Cr	1066	Amort of Prem on Debt-2018A1	$ (642,424)
[21]	2026	429000	Amort of Prem on Debt-Cr	1067	Amort of Prem on Debt-2018A2	$ -
[22]	2026	429000	Amort of Prem on Debt-Cr	1068	Amort of Prem on Debt-2018A3	$ (17,037)
[23]	2026	429000	Amort of Prem on Debt-Cr	1069	Amort of Prem on Debt-2018A4	$ -
[24]	2026	429000	Amort of Prem on Debt-Cr	1070	Amort of Prem on Debt-2019A	$ (818,842)
[25]	2026	429000	Amort of Prem on Debt-Cr	1071	Amort of Prem on Debt-2020A	$ (239,520)
[26]	2026	429000	Amort of Prem on Debt-Cr	1072	Amort of Prem on Debt-2020B	$ (1,322,540)
[27]	2026	429000	Amort of Prem on Debt-Cr	1073	Amort of Prem on Debt-2020C	$ (378,036)
[28]	2026	429000	Amort of Prem on Debt-Cr	1074	Amort of Prem on Debt-2021A	$ (351,444)
[29]	2026	429000	Amort of Prem on Debt-Cr	1075	Amort of Prem on Debt-2021B	$ (947,009)

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Table C4

Table C4: Amortization of Premium or Discount

Line No.	Fiscal Year [A]	Account Number [B]	Account Name [C]	Sub Account [D]	Sub Account Cost Type [E]	Balance Year-To-Date [F]
[30]	2026	429000	Amort of Prem on Debt-Cr	1076	Amort of Prem on Debt-2022A	$ (188,504)
[31]	2026	429000	Amort of Prem on Debt-Cr	1077	Amort of Prem on Debt-2022B	$ (332,563)
[32]	2026	429000	Amort of Prem on Debt-Cr	1078	Amort of Prem on Debt-2023A	$ (392,366)
[33]	2026	429000	Amort of Prem on Debt-Cr	1079	Amort of Prem on Debt-2023B	$ (194,779)
[34]	2026	429000	Amort of Prem on Debt-Cr	217	Amort of Prem on Debt-2024A	$ (648,692)
[35]	2026	429000	Amort of Prem on Debt-Cr	218	Amort of Prem on Debt-2024B	$ (64,448)
[36]	2026	429100	Amort of Gain on Reacq Debt	1016	2000A Amort Gain on Reac Debt	$ (37,678)
[37]	2026	429100	Amort of Gain on Reacq Debt	1071	2020A Amort Gain on Reac Debt	$ (41,949)
[38]	2026	429100	Amort of Gain on Reacq Debt	1072	2020B Amort Gain on Reac Debt	$ (88,717)
[39]	2026	429100	Amort of Gain on Reacq Debt	1074	2021A Amort Gain on Reac Debt	$ (401,568)
[40]	2026	429100	Amort of Gain on Reacq Debt	1076	2022A Amort Gain on Reac Debt	$ (202,963)
[41]	2026	429100	Amort of Gain on Reacq Debt	1079	2023B Amort Gain on Reac Debt	$ (126,180)
[42]	2026	429100	Amort of Gain on Reacq Debt	218	2024B Amort Gain on Reac Debt	$ (65,576)
[43]						$ 0
[51]	**Total Amortization of Premium or Discount**					$ (6,274,637)

Source: TFR Backup, [WP8 Amortization of prem or dis] & [WP9 Bond Issu Amort Exp Detail] tabs.

Table E1

Table E1: Transmission Operations and Maintenance (O&M) Expenses

Line No.	Item	FERC Account No./Calculation	Actual Total [A]	Actual Labor-Related [B]
[1]	**Operation**			
[2]	Operation, Supervision and Engineering	560	$ 3,534,798	$ 4,220,107
[3]	Load Dispatching	561	$ 769,735	$ 396,146
[4]	Load Dispatch- Reliability	561.1	$ -	$ -
[5]	Load Dispatch- Monitor and Operate Transmission System	561.2	$ -	$ -
[6]	Load Dispatch- Transmission Service and Scheduling	561.3	$ -	$ -
[7]	Scheduling, System Control and Dispatch Services	561.4	$ -	$ -
[8]	Reliability, Planning and Standards Development	561.5	$ -	$ -
[9]	Transmission Service Studies	561.6	$ -	$ -
[10]	Generation Interconnection Studies	561.7	$ -	$ -
[11]	Reliability, Planning and Standards Development Services	561.8	$ -	$ -
[12]	Station Expenses	562	$ -	$ -
[13]	Overhead Line Expenses	563	$ 16,321	$ -
[14]	Underground Line Expenses	564	$ -	$ -
[15]	Transmission of Electricity by Others	565	$ -	$ -
[16]	Miscellaneous Transmission Expenses	566	$ 403,903	$ 366,173
[17]	Rents	567	$ -	$ -
[18]	**Total Operation**		$ 4,724,757	$ 4,982,426

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Table E1

Table E1: Transmission Operations and Maintenance (O&M) Expenses

Line No.	Item	FERC Account No./Calculation	Actual Total [A]	Actual Labor-Related [B]
[19]	**Maintenance**			
[20]	Maintenance Supervision and Engineering	568	$ 184,405	$ 182,250
[21]	Maintenance of Structures	569	$ 611,843	$ 7,601
[22]	Maintenance of Computer Hardware	569.1	$ -	$ -
[23]	Maintenance of Computer Software	569.2	$ -	$ -
[24]	Maintenance of Communication Equipment	569.3	$ -	$ -
[25]	Maintenance of Miscellaneous Regional Transmission Plant	569.4	$ -	$ -
[26]	Maintenance of Station Equipment	570	$ 899,128	$ 520,080
[27]	Maintenance of Overhead Lines	571	$ 106,175	$ 85,814
[28]	Maintenance of Underground Lines	572	$ 129,426	$ 51,913
[29]	Maintenance of Miscellaneous Transmission Plant	573	$ -	$ -
[30]	**Total Maintenance**		$ 1,930,978	$ 847,658
[31]	**Total Operation and Maintenance Expense**	**[18] + [30]**	**$ 6,655,735**	**$ 5,830,084**

Source: TFR Backup, [WP2 O&M - A&G] tab.

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Table E1

Table E1: Transmission Operations and Maintenance (O&M) Expenses

Line No.	Item	FERC Account No./Calculation	Projected Total [C]	Projected Labor-Related [D]
[1]	**Operation**			
[2]	Operation, Supervision and Engineering	560	$ 4,943,609	$ 3,882,391
[3]	Load Dispatching	561	$ 2,255,582	$ 1,459,207
[4]	Load Dispatch- Reliability	561.1	$ -	$ -
[5]	Load Dispatch- Monitor and Operate Transmission System	561.2	$ -	$ -
[6]	Load Dispatch- Transmission Service and Scheduling	561.3	$ -	$ -
[7]	Scheduling, System Control and Dispatch Services	561.4	$ -	$ -
[8]	Reliability, Planning and Standards Development	561.5	$ -	$ -
[9]	Transmission Service Studies	561.6	$ -	$ -
[10]	Generation Interconnection Studies	561.7	$ -	$ -
[11]	Reliability, Planning and Standards Development Services	561.8	$ -	$ -
[12]	Station Expenses	562	$ -	$ -
[13]	Overhead Line Expenses	563	$ 23,843	$ -
[14]	Underground Line Expenses	564	$ -	$ -
[15]	Transmission of Electricity by Others	565	$ -	$ -
[16]	Miscellaneous Transmission Expenses	566	$ 734,293	$ 707,886
[17]	Rents	567	$ -	$ -
[18]	**Total Operation**		$ 7,957,327	$ 6,049,484

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Table E1

Table E1: Transmission Operations and Maintenance (O&M) Expenses

Line No.	Item	FERC Account No./Calculation	Projected Total [C]	Projected Labor-Related [D]
[19]	**Maintenance**			
[20]	Maintenance Supervision and Engineering	568	$ 226,101	$ 226,101
[21]	Maintenance of Structures	569	$ 271,648	$ 10,597
[22]	Maintenance of Computer Hardware	569.1	$ -	$ -
[23]	Maintenance of Computer Software	569.2	$ -	$ -
[24]	Maintenance of Communication Equipment	569.3	$ -	$ -
[25]	Maintenance of Miscellaneous Regional Transmission Plant	569.4	$ -	$ -
[26]	Maintenance of Station Equipment	570	$ 979,405	$ 816,215
[27]	Maintenance of Overhead Lines	571	$ 168,352	$ 168,352
[28]	Maintenance of Underground Lines	572	$ 43,760	$ 15,798
[29]	Maintenance of Miscellaneous Transmission Plant	573	$ -	$ -
[30]	**Total Maintenance**		$ 1,689,266	$ 1,237,063
[31]	**Total Operation and Maintenance Expense**	**[18] + [30]**	**$ 9,646,593**	**$ 7,286,547**

Source: TFR Backup, [WP2 O&M - A&G] tab.

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Table E2

Table E2: Administrative and General (A&G) Expenses

Line No.	Item	FERC Account No.	Actual Account Balance [A]	Projected Account Balance [B]
[1]	Administrative and General Salaries	920	$ 27,211,447	$ 28,799,691
[2]	Office Supplies and Expenses	921	$ 14,837,289	$ 18,288,293
[3]	Administrative Expenses Transferred-Credit (*enter negative*)	922	$ (5,065,922)	$ (5,708,488)
[4]	Outside Services Employed	923	$ 4,536,645	$ 3,659,561
[5]	Property Insurance	924	$ 2,775,317	$ 3,834,500
[6]	Injuries and Damage	925	$ 14,233	$ 136,963
[7]	Employee Pensions and Benefits	926	$ 26,307,091	$ 29,590,865
[8]	Franchise Requirements	927		$ -
[9]	Regulatory Commission Expenses	928	$ 197,736	$ 214,146
[10]	Duplicate Charges - Credit (*enter negative*)	929		$ -
[11]	General Advertising Expenses	930.1	$ 266,405	$ -
[12]	Miscellaneous General Expenses	930.2	$ 287,979	$ 219,988
[13]	Rents	931		$ -
[14]	Maintenance of General Plant	932	$ 3,604,719	$ 5,811,614
[15]	**Total Administrative and General Expense**		$ 74,972,938	$ 84,847,133

Source: TFR Backup, [WP2 O&M - A&G] tab.

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Table E3

Table E3: Revenue Credits

Line No.	Item	Source/Calculation	FERC Account No.	Total Transmission
	Sales for Resale			
[1]	Bundled Non-RQ Sales for Resale		447	$ -
[2]	Bundled Sales for Resale included in Divisor		447	$ -
[3]	**Total Sales for Resale**	**[1] + [2]**		$ -
	Rent from Electric Property			
[4]			454	$ -
[5]			454	$ -
[6]			454	$ -
[7]			454	$ -
[8]			454	$ -
[9]			454	$ -
[10]			454	$ -
[11]			454	$ -
[12]			454	$ -
[13]			454	$ -
[14]	**Total Rent from Electric Property**	**SUM([4]:[13])**		$ -
[15]	**Other Electric Revenues Credited**	**Table E4: [15]**	456	$ -
[16]	**TOTAL REVENUE CREDITS**	**[3] + [14] + [15]**		$ -

Source: TFR Backup, [WP10 Account 456.1] tab.

Colorado Springs Utilities
Formula Rate Workbook
Projections for Rate Year 2026

Table E4

Table E4: Other Electric Revenues

Line No.	Description	Assignment		Total Revenue
[1]	Firm Network	Divisor	$	-
[2]	Long Term Firm	Divisor	$	-
[3]	Other Long Term Firm	Divisor	$	-
[4]	Short Term Firm Point To Point	Credit	$	-
[5]	Non Firm	Credit	$	-
[6]	Other Service	Divisor	$	-
[7]	Distribution Wheeling Fees (Direct)	Divisor	$	102,908
[8]	Non-Firm Off-System Revenues	Credit	$	-
[9]	Schedule 4 - Energy Imbalance Service	Divisor	$	1,547,433
[10]			$	-
[11]			$	-
[12]			$	-
[13]			$	-
[14]			$	-
[15]	**TOTAL REVENUE CREDIT**		$	-

Source: TFR Backup, [WP10 Account 456.1] tab.

Transmission Owner Filing Protocols

CSU Formula Rate Implementation Protocols

Section I. Annual Update

1. The Formula Rate Template of Colorado Springs Utilities ("CSU") set forth in Attachment H, Table 1of the Southwest Power Pool ("SPP") Open Access Transmission Tariff and these Formula Rate Implementation Protocols ("Protocols") together comprise the filed rate ("Formula Rate") of CSU for transmission service in the CSU zone of the SPP footprint. CSU must follow the instructions specified in the Formula Rate to calculate its Annual Transmission Revenue Requirements ("ATRR") and the rates for Network Integration Transmission Service ("NITS") and Point-to-Point Transmission Service in the CSU zone of the SPP footprint, as well as the ATRR for Base Plan Upgrades and other network upgrades. The initial ATRR and the initial rates will be in effect for a partial year from the effective date of CSU's transfer of operational control of its transmission facilities to SPP until December 31, 2026.

2. The Formula Rate shall be applicable to service on and after January 1 of each calendar year through December 31 of the following calendar year ("Rate Year"), and subject to review as provided in these Protocols.

3. On or before September 1 of each calendar year, CSU shall:

   a) Recalculate the ATRR and the rates for zonal NITS, zonal Point-to-Point Transmission Service, and Schedule 1 Service for the new Rate Year in accordance with the Formula Rate ("Annual Update"); and

   b) Provide its Annual Update to SPP and cause such information to be posted on SPP's website and OASIS. Within ten (10) days of such posting, CSU shall provide notice of such posting to all parties on an SPP email exploder list. Interested Parties can contact SPP to subscribe to the SPP "exploder list." For purposes of these Protocols, the term Interested Parties includes, but is not limited to customers under the SPP OATT, state utility regulatory commissions, consumer advocacy agencies, and state attorneys general.

4. If the date for posting the Annual Update falls on a weekend or a holiday recognized by the Federal Energy Regulatory Commission ("FERC"), then the posting shall be due on the next business day. The date on which any such posting occurs shall be that year's "Publication Date". Any delay in the Publication Date will result in an equivalent extension of time for the submission of Information Requests discussed in Section III of these Protocols.

5. CSU shall request SPP to submit to FERC an Informational Filing as provided in Section VI of these Protocols.

6. The Annual Update for the Rate Year shall:

    a. Include a workable data-populated Formula Rate Template and underlying workpapers in native format with all formulas and links intact;

    b. Provide the Formula Rate calculations and all inputs thereto, as well as supporting documentation and workpapers for data that are used;

    c. Provide sufficient information to enable Interested Parties to replicate the calculation;

    d. Identify all material adjustments made to the Formula Rate data in determining formula inputs;

    e. With respect to any change in accounting that affects inputs to the Formula Rate or the resulting charges billed under the Formula Rate ("Accounting Change"):

        i. Identify any Accounting Changes, including:

            1. the initial implementation of an accounting standard or policy;

            2. the initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;

            3. correction of errors and prior period adjustments that impact the calculation;

            4. the implementation of new estimation methods or policies;

        ii. Identify items included in the calculation at an amount other than on a historic cost basis (e.g., fair value adjustments);

        iii. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs;

        iv. Provide, for each item identified pursuant to items I.6.e.i - I.6.e.iii of these protocols, a narrative explanation of the individual impact of such changes on the calculation.

Section II. Review of Annual Update

1. CSU shall hold an open meeting among Interested Parties ("Annual Meeting") no sooner than seven (7) days and no later than thirty (30) days from the Annual Update Publication Date. No less than seven (7) days prior to such Annual Meeting, CSU shall provide notice on SPP's website and OASIS of the time, date, and location of the Annual Meeting and CSU shall provide notice of such meeting to an SPP email exploder list. The Annual Meeting will be hosted by CSU in the forum of its choice which may include video conferencing, webinar, internet conferencing, phone conferencing, in person, or other similar options. CSU shall provide remote access for Interested Parties to participate in the meeting. The Annual Meeting shall (i) permit CSU to explain and clarify its Annual

Update and (ii) provide Interested Parties an opportunity to seek information and clarification from CSU about the Annual Update.

2. Each year CSU shall endeavor to coordinate with other Transmission Owners in SPP using formula rates to establish revenue requirements for recovery of the costs of transmission projects that utilize the same regional cost sharing mechanism and hold a joint informational meeting to enable all Interested Parties to understand how those transmission owners are implementing their formula rates for recovering the costs of such projects.

Section III. Information Exchange Procedures

1. Each Annual Update shall be subject to the following information exchange procedures ("Information Exchange Procedures"):

    a. Interested Parties shall have until October 31 following the Publication Date (unless such period is extended with the written consent of CSU or by FERC order) to serve reasonable information and document requests on CSU ("Information Exchange Period"). If October 31 falls on a weekend or a holiday recognized by FERC, the deadline for submitting all information and document requests shall be extended to the next business day. Such information and document requests shall be limited to what is necessary to determine:

        i. the extent, effect or impact of an Accounting Change;

        ii. whether the Annual Update fails to include data properly recorded in accordance with these protocols;

        iii. the proper application of the Formula Rate and procedures in these protocols;

        iv. the accuracy of data and consistency with the Formula Rate of the calculations shown in the Annual Update;

        v. the prudence of actual costs and expenditures, including the prudence of CSU's procurement methods and cost control methodologies;

        vi. the effect of any change to the underlying FERC Uniform System of Accounts; or

        vii. any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

    The information and document requests shall not otherwise be directed to ascertaining whether the Formula Rate is just and reasonable.

2. CSU shall make a good faith effort to respond to information and document requests within seven (7) business days of receipt of such requests. Information requests received after 4 p.m. Central Prevailing Time shall be considered received the next business day.

3. CSU will cause to be posted on SPP's website, OASIS and CSU's website (csu.org) all information requests from Interested Parties and CSU's response(s) to such requests; except, however, if responses to information and document requests include material deemed by CSU to be confidential information, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by CSU and the requesting party.

4. CSU shall not claim that responses to information and document requests provided pursuant to these protocols are subject to any settlement privilege, in any subsequent FERC proceeding addressing CSU's Annual Update.

5. No later than December 20th of each year, CSU, upon final approval of CSU's local regulatory body, will provide SPP for posting on SPP's website and OASIS CSU's Annual Update for SPP to include in the Zonal ATRR and resulting rates to become effective January 1st of the following calendar year.

Section IV. Challenge Procedures

1. Interested Parties shall have until October 31 (unless such period is extended with the written consent of CSU or by FERC order) to review the inputs, supporting explanations, allocations and calculations and to notify CSU in writing, which may be made electronically, of any specific Informal Challenges to the Annual Update. The period of time from the Publication Dates until the date Informal Challenges are due shall be referred to as the Review Period. If the date for submitting Informal Challenges falls on a weekend or a holiday recognized by FERC, the deadline for submitting all Informal Challenges shall be extended to the next business day. Failure to pursue an issue through an Informal Challenge shall not bar pursuit of that issue as part of a Formal Challenge with respect to the same Annual Update as long as the Interested Party has included at least one issue as part of an Informal Challenge with respect to that Annual Update. If the Interested Party has not included any issues as part of an Informal Challenge for an Annual Update, the Interested Party is barred from pursuing a Formal Challenge with respect to any issue for that Annual Update but is not barred from pursuing an issue or from lodging a Formal Challenge as to such issue as it relates to a subsequent Annual Update.

2. A party submitting an Informal Challenge to CSU must specify the inputs, supporting explanations, allocations, calculations, or other information to which it objects, and provide an appropriate explanation and documents to support its challenge. CSU shall make a good faith effort to respond to any Informal Challenge within fifteen (15) business days of notification of such challenge. CSU, and where applicable, SPP, shall appoint a senior representative to work with the party that submitted the Informal Challenge (or its representative) toward a resolution of the challenge. If CSU disagrees with such challenge, CSU will provide the Interested Party(ies) with an explanation supporting the inputs, supporting explanations, allocations, calculations, or other information following the Publication Dates.

3. Informal Challenges shall be subject to the resolution procedures and limitations in this Section IV. Formal Challenges shall be filed pursuant to these Protocols and shall satisfy the requirements set forth in section IV.4, IV.7, IV.8, and IV.9.

4. Informal Challenges shall be limited to all issues that may be necessary to determine: (1) the extent or effect of an Accounting Change; (2) whether the Annual Update fails to include data properly recorded in accordance with these protocols; (3) the proper application of the Formula Rate and procedures in these protocols; (4) the accuracy of data and consistency with the Formula Rate of the calculations shown in the Annual Update; (5) the prudence of actual costs and expenditures; (6) the effect of any change to the underlying FERC Uniform System of Accounts; or (7) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula. Any Interested Party seeking to challenge the prudence of actual costs or expenditures shall first raise the matter with CSU in accordance with this Section IV before pursuing a Formal Challenge.

5. CSU will cause to be posted on SPP's website and OASIS all Informal Challenges from Interested Parties and CSU's response(s) to such Informal Challenges; except, however, if Informal Challenges or responses to Informal Challenges include material deemed by CSU to be confidential information, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by CSU and the requesting party.

6. Any changes or adjustments to the Annual Update resulting from the Information Exchange and Informal Challenge processes that are agreed to by CSU will be reported in the Informational Filing required pursuant to Section VI of these protocols and will be reflected in the Annual Update for the following Rate Year, as discussed in Section V of these Protocols.

7. Interested Parties shall have until March 31 (unless such date is extended with the written consent of CSU to continue efforts to resolve the Informal Challenge) to file any Formal Challenges to the Annual Update posted in the previous calendar year.

8. Formal Challenges shall be filed pursuant to these Protocols and shall satisfy all of the following requirements.
   a. A Formal Challenge shall:
      i. Clearly identify the action or inaction which is alleged to violate the filed rate formula or Protocols;
      ii. Explain how the action or inaction violates the filed rate formula or Protocols;
      iii. Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including:
         1. The extent or effect of an Accounting Change;
         2. Whether the Annual Update fails to include data properly recorded in accordance with these Protocols;
         3. The proper application of the Formula Rate and procedures in these Protocols;
         4. The accuracy of data and consistency with the Formula Rate of the charges shown in the Annual Update;
         5. The prudence of actual costs and expenditures.
         6. The effect of any change to the underlying FERC Uniform System of Accounts; or
         7. Any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula
      iv. Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction;
      v. State whether the issues presented are pending in an existing FERC proceeding or a proceeding in any other forum in which the filing party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;
      vi. State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief;
      vii. Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the filing party, including, but not limited to, contracts and affidavits; and
      viii. State whether the filing party utilized the Informal Challenge procedures described in these Protocols with regard to any issue.

b. Any person filing a Formal Challenge must serve a copy of the Formal Challenge on CSU. Service to CSU must be simultaneous with filing at the Commission. Simultaneous service can be accomplished by electronic mail in accordance with 18 C.F.R. § 385.2010(f)(3), facsimile, express delivery, or messenger. The party filing the Formal Challenge shall serve the individual listed as the contact person on CSU's Informational Filing required under Section VI of these Protocols.

9. All Formal Challenges shall be served on CSU on the date of such filing as specified in Section IV.8.b above. A Formal Challenge shall be filed in the same docket as CSU's Informational Filing discussed in Section VI of these protocols. CSU shall respond to the Formal Challenge by the deadline established by FERC. A party may not pursue a Formal Challenge if that party did not submit any Informal Challenge during the applicable Review Period.

10. In any proceeding initiated by FERC concerning the Annual Update or in response to a Formal Challenge, CSU shall bear the burden, consistent with section 205 of the Federal Power Act, of proving that it has correctly applied the terms of the Formula Rate consistent with these protocols, and that it followed the applicable requirements and procedures in these Protocols. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.

11. Except as specifically provided herein, nothing herein shall be deemed to limit in any way the right of CSU to request SPP to file unilaterally, pursuant to Federal Power Act section 205 and the regulations thereunder, to change the Formula Rate or any of its inputs (including, but not limited to, rate of return and transmission incentive rate treatment), or to replace the Formula Rate with a stated rate, or the right of any other party to request such changes pursuant to section 206 of the Federal Power Act and the regulations thereunder.

12. No party shall seek to modify the Formula Rate under the Challenge Procedures set forth in these Protocols, and the Annual Update shall not be subject to challenge by anyone for the purpose of modifying the Formula Rate. Any modifications to the Formula Rate will require, as applicable, a Federal Power Act section 205 or section 206 filing.

13. Any Interested Party seeking changes to the application of the Formula Rate due to a change in the FERC Uniform System of Accounts, shall first raise the matter with CSU in accordance with this Section IV before pursuing a Formal Challenge.

14. The implementation of any changes or adjustments resulting from any Formal Challenge made with FERC will be subject to: (1) approval by CSU's Board of Directors; and (2) SPP Tariff Section 39.1. Further, nothing herein is intended to alter, and does not supersede, sections 3.10, 3.11, and 3.12 of the Southwest Power Pool Membership Agreement.

Section V. Changes to Annual Update

1. Except as provided in Section IV.6 of these Protocols, any changes to the data inputs, including but not limited to changes as the result of any FERC proceeding to consider the Annual Update, or as a result of the procedures set forth herein, shall be incorporated into the Formula Rate and the charges produced by the Formula Rate in the Annual Update for the next Rate Year. This reconciliation mechanism shall apply in lieu of mid-Rate Year adjustments. Interest on any refund or surcharge, if applicable, shall be calculated in accordance with the 18 C.F.R. § 35.19a

2. In the event that CSU is required by applicable law to correct an error, CSU shall correct such error in good faith and without regard to whether the correction increases or decreases CSU’s revenue requirements, in a manner consistent with FERC’s regulations. Nothing in these Protocols should or may be construed as preventing Interested Parties or the FERC from protesting such correction as inappropriate

Section VI. Informational Filings

1. By January 15 of each year, CSU shall request SPP to submit to FERC an informational filing (“Informational Filing”) of its Annual Update for the Rate Year. This Informational Filing must include the information that is reasonably necessary to determine: (1) that input data under the Formula Rate are properly recorded in any underlying workpapers; (2) that CSU has properly applied the Formula Rate and these procedures; (3) the accuracy of data and the consistency with the Formula Rate of the ATRR and rates under review; and (4) the extent of accounting changes that affect Formula Rate inputs. The Informational Filing must also describe any corrections or adjustments made during that period and must describe all aspects of the Formula Rate or its inputs that are the subject of an ongoing dispute under the Informal or Formal Challenge procedures. Within five (5) days of such Informational Filing, CSU shall provide notice of the Informational Filing via an SPP email exploder list and by posting the docket number assigned to CSU’s Informational Filing on SPP’s website and OASIS
2. Any challenges to the implementation of the Attachment H - CSU Formula Rate must be made through the Challenge Procedures described in Section IV of these Protocols and not in response to the Informational Filing.

APPENDICES

Rate

Manual

Colorado Springs Utilities
It's how we're all connected

Rate Manual

Updated September 10, 2024

TABLE OF CONTENTS

Introduction

Colorado Springs Utilities Board (Utilities Board) directs Colorado Springs Utilities (Utilities) to apply ratemaking practices that are just, reasonable and not unduly discriminatory. Pricing of services derive result in revenues that are sufficient to provide safe, reliable utility services to Colorado Springs Utilities citizens and customers while maintaining financial viability of each separate regulated service. The Excellence in Governance Policy Manual includes a specific instruction and guidelines related to pricing of services that establish guidance, structure and transparency in the development of rates (see Appendix).

Furthermore, City Council is directed to apply certain legal standards to the approval of rates for regulated utility products and services. (City Code §12.1.108(E) and (F), contains the standards for energy (E) and water/wastewater (F), and CRS 40-3.5-101 *et seq* of the Colorado Statutes sets forth the standards for energy service beyond municipal limits.) This manual outlines the basic elements involved in determination of the sufficient revenue levels and allocation of the revenue responsibility to the various classes of customers, which is an important first step in the setting of sound rates for services that meet the standards referenced above.

The concepts and procedures described in this manual are based on principles that are generally accepted and widely applied throughout the utility industry. However, due to the unique nature of each utility and the individual utility services offered by different utilities, variations on these concepts and procedures are commonplace within the industry. Courts have recognized that the ratemaking function is as much art as science, and tend to be deferential to rate-setting authorities. The 1944 U.S. Supreme Court *Hope* decision, established that Cost of Service ratemaking is a starting point for determining “just and reasonable” rate(s) and “it is the result reached not the method employed which is controlling.” Consequently, there is no one judicially sanctioned ratemaking methodology, rather there are numerous paths which may lead to rates that meet the relevant legal standards. The Colorado Supreme Court (1997) stated, “Ratemaking is not an exact science, but, rather, a matter of reasoned judgment.”

Generally accepted ratemaking practice to develop utility rates involves the following analytic procedures:

- Determine the total annual Revenue Requirement for the time period when the rates are to be in effect.

- Perform Cost of Service Study that is used to:
  - Functionalize, at the account level, the relevant expenditure items to the basic functional categories, (e.g., for electric, these are generation, transmission and distribution).
  - Classify each functionalized cost into broad categories utilizing cost causation principles (e.g., for natural gas, these are demand, commodity and customer).
  - Allocate to customer classes based on the service characteristic of each individual class.

- Utilize the results from the Revenue Requirement and the Cost of Service analysis to establish cost-based rates that meet the overall rate design goals and objectives of the utility:
  - Produce revenues equivalent to the Revenue Requirement;
  - Maximize utilization of service infrastructure by encouraging efficient usage;
  - Assure maximum stability of revenues;
  - Distribute the total Revenue Requirement reasonably among the different classes of customers; and
  - Promote economic development by attracting and retaining customers within the service territory.

Basic Sources of Data

Colorado Springs Utilities (Utilities) maintains financial and accounting records that utilize a chart of accounts based primarily upon the uniform system of accounts prescribed by the Federal Energy Regulatory Commission and/or the National Association of Regulatory Utility Commissioners.

Utilities develops rates to support the annual Budget. The basic sources of data used to extract a Cost of Service Study include financial forecasting models and historical cost accounting data. The annual Budget is a critical data source that is prepared annually and represents the first year in a five-year Annual Operating and Financial Plan.

Other significant data sources are forecasted customers, sales units and demand by rate class. Customers and sales units are derived from statistically adjusted econometric forecast models and demands are derived from historical load studies. The forecast models assume 30-year normal weather.

Revenue Requirement

The development of the Revenue Requirement is the first analytical step of the ratemaking process. In order to provide adequate utility service to customers, Utilities must receive sufficient revenue from each service to ensure proper operation and maintenance, development and perpetuation of the system and financial stability. Utilities utilizes a version of the Cash-Needs Method to determine the Revenue Requirement. The essence of this method is to provide revenues from the service sufficient to cover all cash obligations as they come due for the period over which the rates are to be in effect. This method is depicted in the following formula:

RR = O&M + SPTC+ DS + CFC +AC

RR = Revenue Requirement

Revenue Requirement is expressed in terms of a forecasted test year for purposes of determining that rate levels are sufficient and rate changes are appropriate. The Revenue Requirement will vary by year, and by service due to the direct relationship to the annual Budget. Utilities develops annual Budget to achieve the outcomes identified as most important to the Utilities Board and customers. Further, the annual Budget supports the financial metrics necessary to maintain a healthy “AA” credit rating and financial stability.

O&M = Operating and Maintenance Expense

O&M expense represents the day-to-day costs Utilities incurs to produce and deliver electricity, natural gas, water, and wastewater treatment services, and perform administrative and general functions.

SPTC = Surplus Payments to the City of Colorado Springs
(electric, natural gas, and water services)

The City Charter of the City of Colorado Springs (City) provides for the appropriation of any remaining surplus of net earnings to the general revenues of the City. Pursuant to its authority as the legislative body for the City and as the ratemaking body for Utilities, City Council has established planned Surplus Payments to the City of Colorado Springs for Utilities' Electric, Natural Gas, and Water services.

DS = Debt Service payments

Debt service payments that include both principal and interest payments associated with outstanding revenue bonds and notes and loans payable.

CFC = Cash Funded Capital

Cash requirements necessary to fund capital projects and balance the need for additional debt service.

AC = Additions to Cash

Cash requirements necessary to maintain financial stability and designated financial metric levels.

Cost of Service Study

Functionalization

Functionalization is the assignment of costs according to distinct operational functions of the specific utility service. The accounting system and the related chart of accounts establish a structure aligned with these operational functions. This system is a means whereby such costs can be assigned or divided among the major utility functions, thereby making a systematic and rational connection to the following steps in the process.

ELECTRIC

The major functions generally used for purposes of cost allocation for electric utilities are:

- Generation
- Transmission
- Distribution
- Customer

The *Generation* function includes all costs involved in the generation of power not included in the Electric Cost Adjustment (see Electric and Gas Cost Adjustment Procedures section). The *Transmission* function includes all costs associated with the high-voltage transfer of power from one geographical location to another within a system. The *Distribution* function includes all costs associated with the transfer of power from the transmission system to the consumers. The *Customer* function includes all other costs involved in providing services to customers that are not included in the other functions.

Natural Gas

The major functions generally used for purposes of cost allocation for natural gas utilities are:

- Production
- Distribution
- Customer

The *Production* function includes all costs involved in the production of manufactured gas, not included in the Gas Cost Adjustment (see Electric and Gas Cost Adjustment Procedures section). The *Distribution* function includes all costs associated with the delivery of natural gas from the city gate to the consumers. The *Customer* function includes all other costs involved in providing services to customers that are not included in the other functions.

Water

The major functions generally used for purposes of cost allocation for water utilities are:

- Source of Supply
- Treatment
- Transmission
- Distribution
- Nonpotable
- Customer

The *Source of Supply* function includes all costs involved in obtaining and delivering raw water to the local treatment plants. The *Treatment* function includes all costs associated with the water treatment process. The *Transmission* function includes all costs related to moving water from the treatment plants to the local storage tanks. The *Distribution* function includes all costs associated with the delivery of water from the storage tanks to the consumers. The *Nonpotable* function includes all costs related to the production of nonpotable water. The *Customer* function includes all other costs involved in providing services to customers that are not included in the other functions.

WASTEWATER

The major functions generally used for purposes of cost allocation for wastewater utilities are:

- Collection
- Treatment
- Sludge Handling
- Customer

The *Collection* function includes all costs involved in the delivery of wastewater from the consumers to the treatment plants. The *Treatment* function includes all costs of treating the wastewater, separating it from the sludge and discharge into the creek or into the nonpotable system. The *Sludge Handling* function includes the cost of conveying, treatment and disposal of the sludge. The *Customer* function includes all other costs involved in providing services to customers that are not included in the other functions.

INDIRECT COSTS

An important part of the functionalization procedure is the arrangement of costs that cannot be directly assigned to distinct operational functions. These costs are incurred on behalf of more than one service or provide benefit to the organization as a whole. These include but are not limited to costs associated with general and common plant, customer accounts, service and information expense and administrative and general (A&G) expense. In a multi-service utility such as Utilities, allocations are applied to assign these expenditures according to a formula consistent with generally accepted ratemaking practices demonstrating a systematic, rational and defensible approach to functionalize indirect costs.

Classification

Classification further segregates the functionalized costs based on attributes bearing a relationship to a measurable characteristic of the service or groups of services. Classification is based on the principle of cost causation; costs are identified as being caused by a service or group of services if:

- the costs exist as a direct result of providing the service or group of services, or
- the costs are avoided if the service or group of services is not provided.

Although it would be ideal if each group of costs could be directly assigned to a particular service characteristic, in practice this will almost never occur.

ELECTRIC

The most widely used classification components for electric utility service are Demand, Energy and Customer. *Demand*-related costs include those items that are related to system capacity and peak usage, and may be separated by the generation, transmission and distribution functions. *Energy*-related costs include those items that relate to the total kilowatt hours consumed during a period of time, and often are separated into peak and off-peak costs. *Customer*-related costs include items, such as billing and accounting that are related to the number of customers served.

An important component of the classification process for electric service is the division of generation and transmission between demand and energy. As a measure of average utilization of system resources (energy) in relation to peak demand the system load factor is used to classify demand and energy portions of generation transmission expenses.

Another important component of the classification process is the division of distribution costs between demand and customer. The design of the distribution system is driven by both the demand on the system and the number of customers connected to the system. Utilities has consistently split the distribution costs between demand and customer by 65% and 35%, respectively.

Natural Gas

The most widely used classification components for natural gas service are Demand, Commodity and Customer. *Demand*-related costs include those items that are related to system capacity and peak usage, and may be separated by the production and distribution functions. *Commodity*-related costs include those items that relate to the total units of gas consumed during a period of time. *Customer*-related costs include items, such as billing and accounting that are related to the number of customers served.

Water

The most widely used classification components for water service are Base, Extra Capacity and Customer. *Base*-related costs are those that tend to vary with the total quantity of water used, plus those O&M expenses and capital costs associated with the average level of service provided throughout the year, referred to as average annual day. *Extra Capacity*-related costs are associated with meeting requirement in excess of the average use; these costs are further subdivided into costs necessary to meet maximum-day and maximum-hour demands. *Customer*-related costs include items, such as billing and accounting that are not related to the amount of service provided.

Wastewater

The most widely used classification components for wastewater service are Volume, Customer, Pretreatment and two strength categories; Biochemical Oxygen Demand (BOD) and Total Suspended Solids (TSS). *Volume*-related costs include those items that are related to the volume of wastewater that is treated. *Customer*-related costs include items, such as billing and accounting that are related to the number of customers served. *Pretreatment*-related costs reflect those cost items related to the various pretreatment programs. The two strength categories represent costs related to reducing the strength loadings to acceptable levels.

Allocation

Allocation assigns the functionalized and classified costs to the various customer classes. A customer class is a relatively uniform group of customers that possess similar characteristics such as load characteristics, delivery volume, customer service costs and other conditions of service. Utilities utilizes forecasted data in the development of allocation factors that include, but are not limited to, the following advantages: 1) alignment of developing Utilities rates consistent with the annual Budget and Budget Appropriation, 2) the underlying data used to develop allocation factors between rate classes will match the billing determinants used in the development of the rates for any particular rate class, 3) forecasted data captures changes in class consumption due to various reasons such as weather patterns and customer shifts from one customer class to another. In some circumstances, certain costs are incurred for the direct benefit of customer classes and as such are directly assigned.

ELECTRIC

The three cost categories utilized for electric service allocations are Demand, Energy and Customer. In 2014, Utilities conducted an Allocation Methodology Project to review and evaluate industry allocation methodologies appropriate for Utilities based upon predefined selection criteria. As a result of this project, Utilities selected and implemented the Average and Excess 3 coincident peak (CP) method for generation and transmission *Demand* costs. This methodology allocates based upon both the contribution of each rate class to average load and the average of the three peak hours of the three highest months. The distribution *Demand* is allocated based on each class' annual non-coincident peak (NCP), with recognition to the voltage level the Customer receives service. The *Energy* costs are allocated on the basis of sales or energy output to lines to each class. The *Customer* costs are allocated based on weighted customer numbers.

NATURAL GAS

The three cost categories utilized for natural gas service allocations are Demand, Commodity and Customer. The gas supply *Demand* costs are allocated to firm gas sales customers based on their CP and to interruptible sales customers based upon an assumed 100% load factor. The *Commodity* costs are allocated to customers based upon their commodity sales. The *Customer* costs are allocated based upon weighted customer numbers.

WATER

The four cost categories utilized for water service allocations are Annual, Maximum Day, Maximum Hour and Customer. The *Annual* (sometimes referred to as the base) costs are allocated based upon sales to each class. The *Maximum Day* costs are allocated based on the daily CP of each class. The *Maximum Hour* costs are allocated based on the hourly CP of each class. The *Customer* costs are allocated based on weighted customer numbers.

WASTEWATER

The five cost categories utilized for wastewater service allocations are Volume, Biochemical Oxygen Demand (BOD), Total Suspended Solids (TSS), Pretreatment and Customer. The *Volume* costs are allocated based on the volume discharged by each group. The *BOD* costs are allocated by the BOD loadings of each group. The *TSS* costs are allocated by the TSS loadings of each group. The *Pretreatment* costs are allocated based on volume discharged by each group. The *Customer* costs are allocated based on weighted customer numbers.

Electric Cost Adjustment (ECA) and Gas Cost Adjustment (GCA)

The cost adjustment is a direct flow-through rate structure, standard in the industry and designed to recover fuel-related costs. Fuel costs are variable and driven by fluctuation in fuel prices, most notably natural gas market prices. Utilities produces and purchases electricity and recovers these fuel-related costs through the Electric Cost Adjustment (ECA). Utilities purchases natural gas and recovers these fuel-related costs through the Gas Cost Adjustment (GCA).

Currently, all retail electric customers and most retail natural gas customers take service under rate schedules that have a cost adjustment clause. The ECA and GCA rates are designed to be modified utilizing City Code § 12.1.107(D), Procedure to Change Certain Rates or Charges and Authorize Refunds by Resolution. Utilities can adjust as often as monthly by Resolution after review by the Office of the City Auditor and approval by City Council. Utilities closely monitors actual sales and forecast data in order to file a proposed ECA and/or GCA rate adjustment with City Council consistent with Cost Adjustment Guidelines identified below.

Initiating a timely response to fluctuation in market prices and consumption supports:

- Providing a price signal to customers based on the true cost of electricity and natural gas;
- Accurately reflecting customers' energy consumption volume and associated costs;
- Effectively managing over and under collection balances; and
- Utilities' financial stability.

Utilities maintains process documentation that codifies and standardizes the ECA and GCA expense accounts.

Electric Capacity Charge

The Electric Capacity Charge rate (ECC) is designed to recover costs associated with the transportation and storage of natural gas and fixed capacity payments to the Western Area Power Administration (WAPA). These expenditures are made in order to reserve transmission capacity related purchased power and natural gas used for electric generation. Capacity costs are allocated to each electric customer class using the Average and Excess 3 coincident peak (CP) method, and recovered through a per kilowatt hour charge.

The ECC rate is designed to be modified utilizing City Code § 12.1.107(D), Procedure to Change Certain Rates or Charges and Authorize Refunds by Resolution. These ECC costs are natural gas and purchase power related and not within the control of Utilities. Utilities is allowed to adjust as often as monthly by Resolution after review by the Office of the City Auditor and approval by City Council.

Natural Gas Capacity Charge

The Natural Gas Capacity Charge (GCC) rate is designed to recover costs associated with transportation and storage of natural gas. These costs are largely comprised of fixed capacity charges in order to ensure firm delivery of natural gas to Utilities. These costs are allocated to each customer class using the Average and Excess coincident peak (CP) method, and recovered through a per hundred cubic feet charge.

The GCC rate is designed to be modified utilizing City Code § 12.1.107(D), Procedure to Change Certain Rates or Charges and Authorize Refunds by Resolution. These GCC costs are natural gas fuel related and not within the control of Utilities. Utilities is allowed to adjust as often as monthly by Resolution after review by the Office of the City Auditor and approval by City Council.

Colorado Clean Heat Plan Charge

State legislation passed in 2021 (Senate Bill 21-264) requires natural gas utilities to adopt programs that encourage customers to reduce emission generated by natural gas-based appliances and heating equipment. To comply with this legislation, Utilities filed its Clean Heat Plan with the State in August of 2023, that outlines how Utilities intends to work with customers to accomplish home-and-business-based emissions reductions. The Colorado Clean Heat Plan Charge recovers the cost of energy efficiency programs needed to meet Colorado's Clean Heat Plan law.

Water and Wastewater Connection Charges and Fees

Each time a new connection is made to the wastewater and/or water system, Utilities requires the payment of a connection charge(s) or fee(s). Such charges are commonly levied in the case of municipal water and wastewater systems. Connection charges serve the purpose of collecting a portion of the costs incurred by past and existing customers in developing the system currently in place in addition to collection of costs incurred for the growth of the system caused by new customers.

The methodology used by Utilities to calculate connection charges follows generally accepted industry standards. The accepted development charge methodology utilized comes from the Colorado Supreme Court in its ruling in *Krupp v. Breckenridge Sanitation District*, issued in early 2001. The basic tenets of that ruling are followed by Utilities in methodology so that the charges are 1) based upon clearly defined needs and costs; and 2) are derived in a manner which fairly apportions costs in accordance with the benefits provided.

The imposition of connection charges mitigates the possibility that existing customers will bear an undue share of the costs of system growth. Funding capital improvements through connection fees greatly decreases the need to collect dollars needed to pay for growth through rate structures that existing customers pay.

Utilities uses the Equity Buy-In approach to ensure that the connection charge balances the sharing of capital costs between existing and new customers. The Equity Buy-In method is generally accepted throughout the country as an appropriate method and is consistent with the standards outlined in the aforementioned *Krupp v. Breckenridge*, and shares the cost of infrastructure between existing and new customers.

The following connection charges and fees are assessed by Utilities:

Water and Wastewater Development Charges

This charge is assessed at the time of connection to the water and/or wastewater system for capacity in the existing system by a new customer within Utilities' service territory. The amount of the fee depends on lot size for residential customers and meter size for nonresidential customers. A multiplier of 1.50 is assessed for customers outside the city limits.

Water Resource Fee

This charge is assessed at the time of connection to the water system for capacity based on the cost of projected capital expenditures for growth and expansion by a new customer within Utilities' service territory. The amount of the fee depends on lot size for residential customers and meter size for nonresidential customers. A multiplier of 1.5 is assessed for customers outside the city limits.

Water and Wastewater Regional System Availability Fees

This charge is assessed at the time of connection to the water and/or wastewater system by a regional customer (institutions, organized water districts, municipal corporations, or other similar organizations) outside the city limits. It is based on the amount of capacity in the existing system utilized by the customer. The charge is determined by the meter size for water regional customers and peak day million gallons per day for wastewater regional customers. A multiplier of 1.20 is assessed for water regional customers and 1.10 for wastewater regional customers.

The use of a multiplier is a standard rate design technique used by local governments to serve customers located outside their jurisdictional limits. In 2017, the Utilities Policy Advisory Committee (UPAC) recommended a multiplier of 20% for regional water service and a multiplier of 10% for regional wastewater service. The UPAC recommendation recognized that the use of a multiplier: is consistent with industry practice; acknowledges citizen investment in infrastructure and system planning; addresses the recovery of administrative cost of finance, legal, billing and water accounting; considers risk associated with regional service with the higher water multiplier reflecting the service's additional complexity.

Appendix

The following Instruction and Guidelines are excerpts from the Excellence in Governance Policy Manual.

INSTRUCTIONS			
Category:	**Utilities Board Instructions to the Chief Executive Officer**	Date of Adoption:	**May 16, 2018**
Policy Title (Number):	**Pricing of Services (I-1)**	Revision Date:	
Monitoring Type:	**Internal**	Revision Number:	
Monitoring Frequency:	**Annual**		
Guidelines:	**Rate Design (G-5)** **Electric and Gas Cost Adjustments (G-6)**		

The Chief Executive Officer shall direct that pricing practices result in rates that are just, reasonable and not unduly discriminatory. Accordingly, the CEO shall:

1. Establish pricing practices that result in revenues that are sufficient to provide safe, reliable utility services to Springs Utilities citizens and customers.

2. Establish pricing practices that maintain financial viability of each separate regulated service.

GUIDELINES			
Guideline:	**Rate Design (G-5)**	Date of Adoption:	**September 19, 2014**
Applicable Policy Title (Number):	**Pricing of Services (I-1)**	Revision Date:	**February 21, 2024**
		Revision Number:	3

Rate Design

1. Rates should be designed applying the principles of economic efficiency and revenue stability.

   A. Economic efficiency supports efficient use of resources, promotes innovative response to changing demand and supply patterns and leads to optimal consumer and utility decision-making in new technologies and resources, such as those that recognize time varying costs and benefits of demand response (i.e., rate design that recover costs that vary with time or demand and/or encourage efficient use of resources).

      A proposed rate may be designed based on the ability of a customer class to influence system efficiency and maintain high load factor usage that result in deferring capital costs for added capacity.

   B. Rates support revenue stability through sufficient and predictable recovery of the approved revenue requirement.

2. The remaining supporting pricing principles of equitable for all customers, customer satisfaction and customer bill stability will be considered holistically in rate design.

   A. A rate is considered equitable for all customers if it is within plus or minus five percent (5%) of the customer class costs established by a Cost of Service study which is done in accordance with pricing standards.

   B. Economic development is an appropriate consideration in the design of rates for certain rate classes because its supports attracting and/or retaining customers in the Colorado Springs area.

3. Prior to rate design, a Cost of Service study should be used, where appropriate, to establish costs assigned to each customer class and may vary substantially from study to study.

   A. Deviation from a Cost of Service study should be described in the rate filing.

GUIDELINES			
Guideline:	**Electric and Gas Cost Adjustments (G-6)**	Date of Adoption:	**January 20, 2016**
Applicable Policy Title (Number):	**Pricing of Services (I-1)**	Revision Date:	**February 21, 2024**
		Revision Number:	3

Electric and Gas Cost Adjustments

1. Springs Utilities produces and purchases electricity and recovers fuel related costs through the Electric Cost Adjustment (ECA). Springs Utilities purchases natural gas and recovers fuel related costs through the Gas Cost Adjustment (GCA).

2. In accordance with City Code 12.1.108(D)(2)(b), Springs Utilities Electric and Natural Gas Rate Schedules allow cost adjustment rates to be changed as often as monthly to pass-through cost in a timely manner in order to:

   A. Respond to fluctuations in fuel markets.

   B. Provide a price signal to customers based on the true cost of electricity and natural gas.

   C. Accurately reflect customer energy consumption and associated costs.

3. Rate adjustments are filed with City Council on a quarterly basis (effective January, April, July and October) to pass-through forecasted fuel related costs.

   A. When collected balances are within plus $10,000,000 or minus $5,000,000, quarterly refunding/recovery of balances will be based on the proportionate share of forecast sales and target a zero-dollar collected balance at the end of a 24-month period.

   B. When collected balances exceed plus $10,000,000 or minus $5,000,000, quarterly refunding/recovery of balances will be based on the proportionate share of forecast sales and target a zero-dollar collected balance at the end of a 12-month period.

4. Based on relevant or unexpected circumstances, Springs Utilities may propose rate adjustments using alternative balance refunding/recovery periods.

Hearing

Procedures

CITY OF COLORADO SPRINGS[1]

RULES AND PROCEDURES OF CITY COUNCIL

Adopted by Resolution No. 36-21, effective March 9, 2021
Amended by Resolution No. 152-22, effective October 25, 2022

[1]Rules of Council are adopted by §3-50 of the Charter of the City of Colorado Springs

PART 4 - UTILITIES PRICING AND TARIFF HEARING PROCEDURE

The following rules, established in accordance with City Code Section 12.1.108 (Regulation of Electric, Streetlight, Natural Gas, Water and Wastewater Rates, Charges and Regulations), shall govern Council hearings concerning the adoption of resolutions which change the pricing or tariff for any regulated utility service of Colorado Springs Utilities (Utilities). (2021)

4-1 HEARING PROCESS

A. Pre-Hearing Procedures

1) The process to change pricing or tariffs for any regulated utility service shall commence with the filing by Utilities of a resolution identifying the proposed changes, accompanied by the proposed tariffs, at a regular or special meeting of Council. Council shall establish a date for a public hearing at that meeting, which hearing shall be no less than thirty (30) calendar days nor more than sixty (60) calendar days from the date of the notice to customers of the proposed resolution.

2) Utilities shall be responsible for notifying customers of proposed changes in pricing or tariffs for any regulated utility service as required by the City Code and Colorado law. Utilities shall place one copy of the Utilities filing and any written documents provided to Council to explain the proposed resolution on file in the office of the City Clerk. These documents shall be available for public inspection.

3) Before or during any public hearing, Council may be assisted by legal, technical or other professional personnel as it deems necessary. If Council retains a professional consultant or advisor, the consultant or advisor shall provide a written report to City Council, Utilities and any customer who has filed a notice of intent under subsection A.8 below at least ten (10) working days prior to the public hearing. A copy shall also be filed with the City Clerk and shall be available for public inspection.

4) If the change in pricing is supported by a cost of service study, Utilities shall provide a draft copy of the proposal and cost of service study to the City Auditor at least thirty (30) calendar days prior to the filing. If the proposed changes do not require a supporting cost of service study, Utilities shall provide a draft of the proposal to the City Auditor seven (7) calendar days prior to the filing of the proposed resolution. If the City Auditor chooses to file a report on the proposal, such report shall be filed with the City Clerk and Utilities at least five (5) calendar days prior to the public hearing.

5) Drafts of the proposed resolution and tariff sheets will be provided to the City Attorney seven (7) calendar days prior to filing with City Council.

6) Subsequent to the Utilities filing and before the public hearing, Utilities may make the following changes to its filed proposal provided that copies of any changes are filed with the City Clerk and sent to customers who have notified the City Clerk of their intention to present witnesses: a) minor corrections or administrative clarifications to the Utilities' filing; b) supplements containing additional information necessary or appropriate to substantiate the filing; and/or c) modifications which reduce the amount of the change requested.

7) Prior to the public hearing, no increase in the prices as noticed may be proposed without notification to all customers who notified the City Clerk of their intention to present witnesses at the hearing and without publication of such changes at least once in a newspaper of general circulation within the City. Material supporting any proposal to increase the prices as previously noticed must be filed with the City Clerk and held open for public inspection.

8) The representative or attorney of a customer who wishes to present testimony by witnesses other than the customer must file a notice of intent with the City Clerk disclosing the names of witnesses, a short summary of testimony and a copy of all exhibits and other documentation to be presented to City Council no less than seven (7) working days prior to the public hearing. A copy of all such material must be filed at the same time with the Utilities' Pricing Department Manager.

9) There is no formal right to discovery, but parties are urged to share information in order to expedite the proceeding. Parties are also encouraged to meet in advance of the hearing to narrow or resolve the disputed issues between them. Nothing shall prohibit the Utilities from meeting with customers outside of the hearing process to discuss proposed changes in pricing or tariffs and to solicit their input.

B. Hearing Procedures

1) City Council shall hear the matter in its legislative capacity. The Colorado Court Rules of Civil Procedure and the Rules of the Public Utilities Commission of the State of Colorado shall not apply to the proceedings. City Council is not bound by the rules of evidence. City Council may take notice of general, technical or scientific facts, or of laws, regulations or court decisions without the necessity of presentation of evidence.

2) At the public hearing, Utilities shall make a presentation to explain the filing and the need for changes in pricing or tariffs. Any customer shall be allowed to present testimony and/or exhibits relevant to the proposed changes during that portion of the public hearing when public comment is allowed.

3) At the public hearing, City Council may question witnesses and may allow such questioning, rebuttal or argument by Utilities, and by customers, their attorneys or representatives, as City Council deems appropriate. City Council may limit the time for presentation by Utilities, customers and their attorneys or representatives, as it deems appropriate. Testimony must be relevant to the issues being heard and shall not be repetitious. If the testimony or exhibits are repetitious, City Council may require all similarly interested customers to designate a spokesperson or may appoint one for them.

4) No party shall have a right to present written briefs during or at the conclusion of the public hearing, unless requested by City Council.

5) Pursuant to the legal requirement that pricing and tariff decisions must be based on information contained “on the record”, once the proposed resolution has been filed if Councilmembers have communications about matters subject to decision outside of the public hearing such communications are considered to be “ex parte communications”. When an ex parte communication occurs, the pertinent details of the communication should be noted during the public hearing. In recognition of the fact that Councilmembers also serve on the Utilities Board, and that Councilmembers/Board members and members of Utilities staff frequently communicate on a number of issues, if an ex parte communication occurs between a Councilmember and a staff member of Utilities, the staff member will reduce the pertinent elements of the communication to writing. The writing will be distributed to all Councilmembers and customers who have filed notices of intent, and shall be placed on file with the City Clerk as part of the record of the proceeding.

C. Post-Hearing Procedures

1) At the conclusion of the public hearing, City Council shall identify issues for deliberation and decision. City Council may adjourn to another time to complete its deliberation and make a decision on the issues. City Council may revise any proposed pricing or tariff as a result of the information presented at the public hearing. All decisions made by City Council shall be based on the record.

2) After its deliberations, City Council shall instruct the City Attorney or designee to draft a proposed Decision and Order. The Decision and Order shall incorporate a description of the history of the proceeding, the issues identified by City Council for deliberation, and City Council's findings on the issues.

3) The written Decision and Order of City Council shall be incorporated in a Resolution of City Council revising pricing or tariffs. The Decision and Order shall be adopted in open public session and shall be placed on file with the City Clerk. It shall identify the date on which changes in pricing or tariffs were approved and the date on which they shall become effective.

4) All prices, as established by City Council in these proceedings, shall meet the requirements of the City Code. All prices shall be designated in tariff sheets and shall remain on file in the City Clerk’s Office and the Utilities Pricing Department.

5) No party shall have the right to request rehearing, re-argument or reconsideration of the decision of City Council.

6) The Utilities filing and supporting documentation, all subsequent documents submitted to City Council or the City Clerk by Utilities, customers or their representatives, the report of the City Auditor, the presentations to City Council by any party, all City Council deliberations, its Decision and Order, and the Resolution adopted, shall constitute the record of these proceedings.

4-2 EXPEDITED HEARING PROCESS FOR INSTANCES OF GOOD CAUSE

A. Instances for Which Good Cause Exists (2011)

1) Certain pricing and tariff changes may be made, or refunds authorized, without meeting the notice and public hearing requirements imposed by Section I of this Part 4, provided that good cause exists. In the following instances, good cause exists:

a. Changes to the gas cost adjustment to reflect increased or decreased gas costs.

b. Changes to the electric cost adjustment to reflect increased or decreased costs of the fuel used for electric generation or purchased power costs.

c. Refunds to customers.

d. Changes to other fees, rates or charges that are not within the control or discretion of the City or the Utilities.

e. Changes to the pricing of water necessary to avoid a water shortage.

f. Tariff changes which have no adverse impact on customers.

2) City Council may find that good cause exists in other instances, and must state the nature and circumstances of the good cause in the resolution resulting from its action.

B. Process for Expedited Hearing

1) Proceedings for consideration of matters for which good cause exists shall be conducted in a legislative manner as a City Council item.

2) When Utilities proposes changes to the gas cost adjustment or the electric cost adjustment, drafts of the proposal including the proposed resolution and tariffs will be provided to the City Auditor and the City Attorney seven (7) calendar days prior to filing the proposal with City Council. If the City Auditor finds that the proposed adjustment is adequately supported and conforms to the requirements of the cost adjustment tariffs, the City Auditor will provide such findings in a letter to the City Council that will be included in the filing by Utilities. If the proposed changes to the gas cost adjustment or the electric cost adjustment are supported by a letter from the City Auditor, the resolution effecting the change will be placed on the City Council's Consent Calendar. (2011)

3) The resolution adopting changes shall be considered an Order of City Council, shall specify the changes to be made and shall state: a) the circumstances which establish good cause and necessitate the change being made under these procedures, b) the effective date of the changes, and c) the manner in which the changes shall be published. (2000, 2004; 2011)