PUBLIC UTILITY DISTRICT NO. 1 OF CHELAN COUNTY
327 N WENATCHEE AVENUE
WENATCHEE WA 98801

REGULAR COMMISSION MEETING

AUGUST 21, 2023

STUDY SESSION
10:00 AM

1. Pledge of Allegiance and Safety/HPI Minute – Gage Graika

2. Approval of the Agenda

3. Quarterly Financial Review and Investment Report

4. Quarterly Energy Resources Update

5. Public Comment
   Time reserved for public comments or questions related to matters not covered by the agenda

BUSINESS SESSION
1:00 PM

Consent Agenda

6. Minutes of the August 7, 2023 Regular Meeting and August 8, 2023 Special Meeting

7. Vouchers: Accounts Payable Summary Report dated August 15, 2023:

   a. Vouchers totaling $10,149,081.21;

   b. Approval of Customer Deposit Returns and Conservation Incentive payments for the period August 01, 2023 through August 14, 2023 in the amount of $62,675.90.

   c. Approval of the net Payroll, Warrant Nos. 238231 through 238239 and Advice Nos. 760787 through 761626 for the pay period ending July 30, 2023 in the amount of $2,614,653.53.

   d. Approval of Warrant Nos. 29915 through 29985 totaling $84,628.84 for claim payments from the workers' compensation self-insurance fund for the period ending August 14, 2023.

e. Approval of Parks Reservation System customer refunds for the period July 18, 2023 through August 14, 2023 in the amount of $1,330.00.

8. A RESOLUTION RATIFYING FIELD WORK ORDER/CHANGE ORDER NOS. B-14, B-15, B-16, B-17, B-18, B-19 AND A-04, AUTHORIZING FINAL ACCEPTANCE OF PERFORMANCE UNDER CONTRACT NO. 18-33 FOR THE ROCK ISLAND HYDROELECTRIC SUPPORT FACILITY IMPROVEMENTS PROJECT WITH LYDIG CONSTRUCTION, INC. OF SPOKANE AND AUTHORIZING RELEASE OF THE BOND IN LIEU OF RETAINAGE

Regular Agenda

9. A RESOLUTION ESTABLISHING NEW TERMS OF SERVICE FOR RATE SCHEDULE 35 AND NEW RATES AND TERMS OF SERVICE FOR RATE SCHEDULE 36

10. A RESOLUTION AUTHORIZING AMENDMENT NO. 6 TO SERVICES AGREEMENT (SA NO. 20-11086) WITH ENGLOBE CORP TO PROVIDE THIRD PARTY INSPECTION SERVICES

11. A RESOLUTION APPROVING BUDGET REVISION, BID ADVERTISEMENT, AWARD AND CONTRACT SIGNATURE FOR LAKE CHELAN POWER TUNNEL ISOLATION SYSTEM (BID NO. 22-12725)

12. Manager Items

13. Commission Items

14. Follow-up on Delegation of Action Items from Previous Board Meeting

15. Delegation of Action Items

16. Additional Public Comment

17. Matters of general business as may necessarily come before the Commission

18. Executive Session: To discuss with legal counsel agency enforcement actions, litigation, potential litigation to which the District or its board is, or is likely to become, a party, and/or legal risks, as authorized by RCW 42.30.110(1)(i) for ___ minutes

This agenda and resolutions (if any) may be revised by the Commission as appropriate.

RESOLUTION NO. _____

A RESOLUTION RATIFYING FIELD WORK ORDER/CHANGE ORDER NOS. B-14, B-15, B-16, B-17, B-18, B-19 AND A-04, AUTHORIZING FINAL ACCEPTANCE OF PERFORMANCE UNDER CONTRACT NO. 18-33 FOR THE ROCK ISLAND HYDROELECTRIC SUPPORT FACILITY IMPROVEMENTS PROJECT WITH LYDIG CONSTRUCTION, INC. OF SPOKANE AND AUTHORIZING RELEASE OF THE BOND IN LIEU OF RETAINAGE

FACTUAL BACKGROUND AND REASONS FOR ACTION

On April 2, 2018, by Resolution No. 18-14232, the Commission authorized the General Manager to invite sealed proposals to provide General Contractor Construction Manager (GC/CM) services to the District in support of planned improvements to Rock Island Dam and Rocky Reach Dam operation and maintenance facilities. Work at both sites included installation of site utilities and demolition, construction and/or refurbishment of buildings for fabrication, machine work, sandblast, paint, warehouse, office, crew facilities, storage, hazardous material handling, and various other activities. The work at Rock Island Dam was separated from work at Rocky Reach Dam. This Resolution addresses the work required at Rock Island Dam.

On August 20, 2018, by Resolution No. 18-14257, the Commission authorized the General Manager to enter into a contract with Lydig Construction, Inc. (Lydig) for the Rock Island Improvement phase. This contract, known as the A133, governed the general terms between the District and Lydig. The A133 also included a not to exceed dollar amount of $220,000.00 for pre-construction services. Final negotiations with Lydig reduced the not to exceed dollar amount for pre-construction services to $200,000.00.

On June 17, 2019, by Resolution No. 19-14354, the Commission authorized the General Manager to enter into a Guaranteed Maximum Price (GMP) Amendment with Lydig for a not to exceed amount of $19,830,830.00, for the Rock Island Dam Improvements, which resulted in a revised total contract price of $20,030,830.00.

Previously Approved Field Work Order/Change Orders

On October 7, 2019 by Resolution No. 19-14388, the Commission authorized the General Manager to execute Field Work Order/Change Order (FWO/CO) No. B-01 with Lydig for a not to exceed amount of $275,000.00 for adding the C-19 Building sitework. After negotiations with Lydig, the total amount of FWO/CO No.

B-01 was $257,929.00, which resulted in a revised total contract price of $20,288,759.00.

On November 18, 2019 by Resolution No. 19-14397, the Commission ratified FWO/CO No. B-02 which modified the Contract with the following changes: (1) additional work at the water reservoir; (2) revision to the C-22 Building canopies; (3) additional foundation work on the C-22 Building; (4) schedule delays caused by C-22 Building Foundation revisions, and (5) ordering the elevator for the C-19 Building because of a long lead time for delivery. The cost of these modifications was $175,237.00 which resulted in a revised total contract price of $20,463,996.00.

In addition, under the same Resolution No. 19-14397, the Commission authorized the General Manager to execute FWO/CO No. B-03 to build the C-19 Building and revised site utilities. The cost of these modifications was estimated to be $6,294,692.00. After final negotiations with Lydig, the total amount of FWO/CO No. B-03 was $6,268,823.00, which resulted in a revised total contract price of $26,732,819.00.

On February 16, 2021, the Commission approved Resolution No. 21-14535 which ratified and approved FWO/CO Nos. A-01, A-02, A-03, B-04, B-05, B-06, B-07, B-08, B-09, B-10, B-11 and B-12 which increased the contract price by $493,114.00 for a revised total contract price of $27,225,933.00.

On April 5, 2021, by Resolution No. 21-14545, the Commission ratified FWO/CO No. B-13 to include work to pave the access road to the project, employee parking area and C-22 shop west side building access, as well as other minor changes. The contract price was increased by $459,578.00 which resulted in a new not to exceed contract price of $27,685,511.00.

Executed FWO/COs To Be Ratified

The work in FWO/CO Nos. B-14 through B-19 and A-04 consists of conditions and work not anticipated or included in the original contract but within the scope of the contract. The District's staff has executed FWO/CO Nos. B-14 through B-19, which are on file in the offices of the District and summarized as follows:

FWO/CO No.	Description	Amount
B-14	Extend substantial completion date	$0.00
B-15	Field changes, reducing negotiated support services and contingency funds, and extension of completion date	$159,666.00
B-16	Field changes, reducing negotiated support services fund and extension of completion date	$34,423.00
B-17	Piping modifications, sand blast equipment and door modifications	$99,506.00

FWO/CO No.	Description	Amount
B-18	Extend substantial completion date	$0.00
B-19	Extend substantial completion date	$0.00
A-04	Reconciliation of the total contract price for Preconstruction Services	($2,235.47)
Total		**$291,359.53**

FWO/CO Nos. B-14 through B-19 and A-04 result in a net increase in the contract price of $291,359.53 for a revised contract price of $27,976,870.53 (excluding sales tax), which the District's Engineers recommend be ratified. The General Manager of the District concurs with staff's recommendations.

Final Acceptance of Work

District staff has determined that the work required under the contract has been performed in accordance with the terms of the contract and recommends that the District accept the work.

District staff has determined that the completion of all contract work occurred on July 19, 2023. In accordance with the terms of the contract, the Contractor has provided a bond in lieu of retainage equal to 5% of the contract price.

The General Manager of the District concurs with staff's recommendations that the District accept the work performed by the Contractor and recommends the District authorize the release of the related bond in lieu of retainage, subject to the requirements of the contract and state law.

ACTION

IT IS RESOLVED BY THE COMMISSION OF PUBLIC UTILITY DISTRICT NO. 1 OF CHELAN COUNTY, WASHINGTON, as follows:

Section 1. The Commission finds that FWO/CO Nos. B-14 through B-19 and A-04 be ratified and was properly executed pursuant to the authority delegated by Resolution No. 17-14215 and said FWO/COs are hereby formally acknowledged and ratified.

Section 2. All the contract work required under Contract No. 18-33 for the Rock Island Hydroelectric Support Facility Improvements project was completed on July 19, 2023, and the same is hereby accepted, subject to Section 3 hereof. Release of the Contractor’s bond in lieu of retainage is authorized subject to Section 3 and Section 4 hereof, and subject to the provisions and limitations of Chapter 39.12 RCW (Prevailing Wages on Public Works) and 60.28 (Liens for Labor, Materials and Taxes on Public Works).

Section 3. This resolution shall not constitute an acceptance by the District of any work performed or goods supplied pursuant to the aforementioned contract, which are not in strict compliance with the contract terms and conditions.

Section 4. After the expiration of the forty-five (45) day period for giving the District notice of lien and after receipt of the Department of Revenue's certification of the Contractor's payment of taxes, the Employment Security Department's Certificate of Payment of Contributions, Penalties and Interest on Public Works Contracts, and the Department of Labor & Industries' Certificate of Release of the State's Lien on Public Works Contracts and the District being satisfied that taxes certified as due or to become due are discharged and the filed claims of materialmen and laborers, if any, together with a sum sufficient to pay costs of foreclosing the liens and attorney's fees, have been paid, the District's General Manager is authorized and directed to release the bond in lieu of retainage. In the event said taxes, claims, expenses and fees have not been paid, the General Manager is authorized and directed to file a claim against the bond in lieu of retainage in an amount equal to unpaid taxes and unpaid claims, together with a sum sufficient to defray the costs and attorney fees incurred in foreclosing the lien of such claims, and following payment of such claim, release the bond in lieu of retainage.

DATED this 21st day of August 2023.

_____
President

ATTEST:

_____ _____
Vice President Secretary

_____ _____
Commissioner Commissioner

Seal

RESOLUTION NO. _____

A RESOLUTION ESTABLISHING NEW TERMS OF SERVICE FOR RATE SCHEDULE 35 AND NEW RATES AND TERMS OF SERVICE FOR RATE SCHEDULE 36

FACTUAL BACKGROUND AND REASONS FOR ACTION

The District has the authority to create rate classes and to establish and modify rates. The District, if it has revenue obligation outstanding, is required to establish, maintain, and collect rates or charges for electric energy and water and other services, facilities, and commodities sold, furnished, or supplied by the District in compliance with RCW 54.24.080. The rates and charges must be fair, nondiscriminatory and adequate to provide revenues sufficient for the payment of the principal of and interest on such revenue obligations for which the payment has not otherwise been provided and all payments which the District is obligated to set aside in any special fund or funds created for such purpose, and for the proper operation and maintenance of the public utility and all necessary repairs, replacements, and renewals thereof. This resolution revises Rate Schedule 35 and Rate Schedule 36.

The District adopted and implemented Rate Schedule 35 in 2016 as a means to mitigate operational and financial costs associated with serving the energy intensive loads associated with server farms and similar high density technological operations. In 2018, The District adopted and implemented Rate Schedule 36 for electric services delivered to cryptocurrency processing, blockchain processing, and similar loads.

In 2022, the District's Commissioners directed staff to prepare a rate proposal to update rates and terms of service to data centers, which include cryptocurrency and non-cryptocurrency data processing and similar operations. As a result, staff presented a proposal on July 24, 2023 during a regularly scheduled board meeting, and the Commission held a Public Rate Hearing on August 7, 2023, that proposed adjustments to the rate class applicability, a revised Energy charge calculation for Rate 36, as well risk mitigation measures for distribution system operations and financial sustainability to further the District's ability to ensure it can serve this new type of load in a just and reasonable manner and consistently with prudent long-term planning, including protection for other customers. The recommended revised Rate Schedule 35 is set forth in Exhibit "A"; the revised Rate Schedule 36 is set forth in Exhibit "B". The Rate Schedules 35 & 36 Staff Report is set forth in Exhibit "C".

Staff recommends that the Board of Commissioners adopt the Staff Report and the amended Rate Schedules 35 and 36. The General Manager has reviewed staff's recommendations and concurs in the same.

After fully considering the public presentations by staff on and after July 2023, comments from members of the public including cryptocurrency and HDL

customers, and the Staff Report, the Commission concurs with staff recommendations including:

RECOMMENDATIONS

Rate Schedule 35 revisions:

- Move server farms from Schedule 35 to Schedule 36 so all data centers are served through Schedule 36 regardless of whether they perform cryptocurrency-related data processing
- Lower the Schedule 35 size limit from 5 aMW to 3 MW to be consistent with Schedule 36

Rate Schedule 36 revisions:

- Revise the energy rate to be a blend of production cost and market costs and automatically adjust the ratio based on total load of the rate schedule
- Update other energy charges as well as update the risk premium methodology
- Add minimum monthly purchase obligation
- Increase the regular security deposit to 3 months of the estimated bill
- Prioritize interruptability of the rate class
- New loads will not be approved where serving substation capacity would exceed 70% of design capacity after load addition
- New loads will not be approved where total load served by a substation under the rate schedule would exceed 3 MW

ACTION

IT IS RESOLVED BY THE COMMISSION OF PUBLIC UTILITY DISTRICT NO. 1 OF CHELAN COUNTY, WASHINGTON, as follows:

Section 1. Requirements for meetings and notices as established by Resolution No. 18-14256 have been met and exceeded.

Section 2. The electric rate classifications, rates, and terms set forth in the rate schedules hereto as Exhibit A and Exhibit B are determined to be fair, reasonable, necessary and not discriminatory. The *Final Rate Schedule 35 & 36 Staff Report* attached hereto as Exhibit C is hereby adopted by the Board together with this resolution as the Board's record of decision. The classification, rates, and rate schedules set forth as Exhibit A and Exhibit B are effective February 1, 2024. The 2023 annual adjustment of the Rate Schedule 36 market energy charge is further deferred until such time as the new electric rate classifications, rates, and terms described herein and detailed in Exhibits A and B become effective.

Section 3. The adoption of this rate resolution is not a major action under the State Environmental Policy Act, and as such is categorically exempt under S.E.P.A guidelines, WAC 197-11-800(14)(i).

Section 4. All prior resolutions inconsistent with this resolution are hereby rescinded and superseded.

Dated this 21st day of August 2023.

_____
President

ATTEST:

_____ _____
Vice President Secretary

_____ _____
Commissioner Commissioner

Seal

EXHIBIT A

High Density Load

Rate Schedule 35

AVAILABILTY:

This schedule applies to loads with an energy use intensity (EUI) of 250 kWh/ft^2/year or more and with average electrical loads up to and including 3 MW at a single Point of Delivery, excluding Schedule 36 loads, where:

- "Energy Use Intensity" or "EUI" means the annual kilowatt-hours of Energy usage divided by the operating space square footage used by the Energy consuming activity as determined by the District; and
- "Server farm" means an entity whose Energy use serves mostly one or more computer server machines and any ancillary loads including HVAC, UPS, power systems, and lighting.

When calculating the EUI, the District may make reasonable assumptions and projections as necessary to estimate Energy usage and square footage based on the Customer's application, data regarding similar operations, and other sources. An entity otherwise subject to this Schedule will be excluded from this schedule if the entity demonstrates to the District's reasonable satisfaction, or the District determines on its own initiative, that the energy use intensity (EUI) of the subject facility is less than 250 kWh/ft^2/year. A Customer otherwise subject to this schedule on its effective date may, at the District's discretion, have the option of entering into a customer-specific service Contract that may include a phase-in of the rate in this Schedule based on the special circumstances of the Customer.

Service under this schedule may require a power sales Contract between the Customer and the District prior to connection of service. Changes in Load, as defined in Utility Service Regulation 41, will require a new service application to be submitted to the District to evaluate the impact of that changed load to existing Electrical Service Facilities.

Customers subject to the terms and conditions of Schedule 35 must meet the following characteristics:

- Be served at one Premise through a single Point of Delivery as defined in the District's Service Regulations;
- Be in compliance with Chapter 296-46B WAC electrical safety standards, administration and installation; and
- Maintain satisfactory Power Factor determined in Schedule 24.

Customers with multiple locations and Energy loads will not be aggregated for billing purposes unless the District, in its sole discretion, determines the Customer is circumventing the 3-MW Energy cap to meet the load requirements of a common Premise. A Customer with measured total connected loads greater than 3 MW may be required to be served under Rate Schedule 4.

UPFRONT CAPITAL CHARGE

Prior to approval of service or increase in capacity, Customers to be served under this schedule must pay an Upfront Capital Charge based upon the requested size of the new or increased amount of electrical load. The Upfront Capital Charge does not apply to load amounts approved by the

District prior to the effective date of this schedule where: (1) the Customer has properly obtained District approval of the load prior to the effective date of this Schedule; (2) the load has not changed materially in load factor, size, or otherwise from the load approved by the District; (3) the Customer has fully complied and continues to fully comply with the District's rules, policies, and regulations; and (4) the load is transferred onto this schedule as of the effective date of the schedule. Current amounts are included in the District's Fees and Charges schedule. Additional state and local taxes may apply. Additional charges may apply, including Line Extension costs.

CHARACTER OF SERVICE:

Service to be furnished under this schedule may be either:

- Three phase, sixty hertz alternating current at primary voltage, or
- Secondary power single phase, three phase or four wire three phase, 60 cycle, alternating current at available phase and voltage up to 2MW.

RATES:

Rate Schedule 35 High Density Load	1/1/2017	12/1/2020	6/1/2021	6/1/2022	6/1/2023	6/1/2024
Basic Charge up to 300kW	$130	$135	$140	$145	$150	$155
Basic Charge 300kW - <1MW	$560	$575	$590	$610	$630	$650
Basic Charge 1MW - ≤ 5MW	$860	$885	$910	$940	$970	$995
Demand Charge	$5.50	$5.65	$5.80	$6.00	$6.20	$6.40
Energy Charge	$0.0270	$0.0278	$0.0286	$0.0295	$0.0304	$0.0313
Upfront Capital Charge	Per kW of new or expanded Electric Service under this schedule. Amount of Upfront Capital Charge is set forth in the District's Fees and Charge Schedule					

TAX ADJUSTMENT:

The amount of any tax levied by any city or town, in accordance with R.C.W. 54.28.070 of the laws of the State of Washington, will be added to all charges for electricity sold within the limits of any such city or town.

SERVICE POLICY:

Service under this schedule is subject to the rules and regulations as defined in the District's Utility Service Regulations.

EFFECTIVE: February 1, 2024

EXHIBIT B

Data Centers and Similar Loads

Rate Schedule 36

AVAILABILITY:

This Schedule applies to data centers and similar computing or data processing loads, regardless of the number of servers/processors, including those related to rack space rental, hosting services, cryptocurrency mining, blockchain, data processing or other loads having, in the District's determination, similar characteristics including any of the following: high energy use density, high load factor, need for more than routine alterations to the District's Electric Service Facilities in order to maintain safety, load that is portable and distributable, highly variable load growth or load reduction as an individual customer and/or in aggregate with similar customers in the District's service area, able to relocate quickly in response to short-term economic signals, high sensitivity to volatile commodity or asset prices, or part of an industry with potential to quickly become a large concentration of power demand in the District's service area. This Schedule does not apply to common computing loads typical in residences and in premises or businesses not primarily involved in data processing.

This rate schedule is available throughout the District's service area with the exception of the Stehekin area and new or expanded service in the areas north and northwest of Leavenworth served by the Anderson Canyon-Summit transmission line and with the further exception of locations that would cause the serving substation to exceed 70% of design capacity or the total load under this rate schedule served by a substation to exceed 3 MW.

Service under this schedule requires a power sales Contract between the Customer and the District prior to connection of service. Changes in Load, as defined in Utility Service Regulation 41, require a new service application to be submitted to the District to evaluate the impact of that changed load to existing Electrical Service Facilities.

Customers subject to the terms and conditions of Schedule 36 must meet the following characteristics:

- Be served at one Premise through a single Point of Delivery as defined in the District's Service Regulations;
- Be in compliance with Chapter 296-46B WAC electrical safety standards, administration and installation; and
- Maintain satisfactory Power Factor determined in Schedule 24; and
- Agree to provide a minimum 60-days advance notice of termination, reduction or change of service.

Customers with multiple locations and Energy loads will not be aggregated for billing purposes unless the District, in its sole discretion, determines the Customer is circumventing the size cap to meet the load requirements of a common Premise. A Customer with measured total connected loads may be required to be served under the rates and terms applicable to such total size.

UPFRONT CAPITAL CHARGE:

Prior to approval of service or increase in capacity, Customers to be served under this Schedule must pay an Upfront Capital Charge based upon the requested size of the new or increased amount of electric load. The Upfront Capital Charge does not apply to load amounts approved by the District prior to the effective date of this Schedule where the load is transferred onto this Schedule as of the effective date of the Schedule. Current amounts are included in the District's Fees and Charges schedule. Additional state and local taxes may apply. Additional charges may apply, including Line Extension costs.

SERVICE OVER 3 MW:

Service will require a Contract between the Customer and the District prior to connection of Service that will address any special circumstances and conditions applicable to the Customer's needs. Contracts will establish the rate and address any terms and conditions considered appropriate by the District, which may include but are not limited to scheduling, maintenance and decommissioning of infrastructure, load balancing, ancillary services, transactional costs, security, and financial risk.

CHARACTER OF SERVICE:

Service to be furnished under this schedule may be either:

Three phase, sixty hertz alternating current at primary voltage, or

Secondary power single phase, three phase or four wire three phase, 60 cycle, alternating current at available phase and voltage up to 1 MW.

RATES - 3 MW AND LESS:

Basic Charge (per month):	6/1/2023	6/1/2024
Up to 300 kW	$150	$155
300 kW to < 1 MW	$630	$650
1 MW to ≤ 3 MW	$970	$995
Monthly Demand Charge, Non-Residential (per KW per month):	$6.20	$6.40
Monthly Demand Charge, Residential (per KW per month):	$16.40	$16.85
Energy Charge:	3.04 ¢/kWh*	
Upfront Capital Charge:	Per kW of new or expanded Electric Service under this schedule. Amount of upfront capital charge is set forth in the District's Fees and Charges Schedule	

* The effective Energy Charge is recalculated at least annually in accordance with the provisions of this Rate Schedule 36. Visit chelanpud.org or call (509) 663-8121 for the current effective Energy Charge. In the event of conflict, the Energy Charge Blending formula below will control.

RESIDENTIAL:

For purposes of the Demand Charge under this rate schedule, residential means premises located in areas of the distribution system that have been designed and constructed for loads with residential characteristics, such as high load diversity and low load size.

BILLING DETERMINANTS:

The billing determinant (in kW) for the Monthly Demand Charge is the greater of the Customer's maximum authorized Demand or the measured demand adjusted for Schedule 24, Power Factor. The billing determinant (in kWh) for the Energy Charge is the greater of the Customer's (a) maximum authorized Demand multiplied by the number of hours in the Billing Period multiplied by 0.9; or (b) Energy usage in the Billing Period.

ENERGY CHARGE BLENDING:

Total load on rate schedule	Energy Charge (¢/kWh)
≤ 10,000 kW	Production Energy Charge: 3.04 ¢/kWh through 5/31/2024, 3.13 ¢/kWh on and after 6/1/2024
> 10,000 kW	A blend of the Production Energy Charge (PEC) and the Market Energy Charge (MEC) using the following ratio, where total load (TL) is in kW: $$Energy\ Charge = \frac{10{,}000kW}{TL} * PEC(¢/kWh) + \frac{TL - 10{,}000kW}{TL} * MEC(¢/kWh)$$

Total load is the sum of the maximum authorized demand of all loads expected to be taking service under the rate schedule during the upcoming 12-month Market Energy Charge period described below. Loads will be expected to be taking service if they are currently taking service or if they have applied for service and made substantial commitments towards commencing service prior to the end of the upcoming 12-month Market Energy Charge period. Loads greater than 3 MW that contract for an energy charge other than the Blended Energy Charge will not be counted towards the total load for purposes of rate blending unless otherwise specified by contract.

The expected total load will be reset annually as of the date the Market Energy Charge is fixed. The District reserves the right to reset the total load at any time, provided that the District will provide affected customers at least 60 days advance notice before an out-of-cycle reset goes into effect.

MARKET ENERGY CHARGE:

The Market Energy Charge will be fixed as of February 1 of each year by the District at the average flat price of the Mid-C Peak and Off-Peak Futures as published daily by the Intercontinental Exchange (ICE) for the 12-month period starting on June 1 plus a 6% administrative fee and plus 3.10¢/kWh). If ICE futures are not published on February 1, they will be fixed as of the next following date they are published. If ICE Mid-C Peak and Off-Peak Futures cease to be published, the District, in its reasonable discretion, may select a replacement source of forward prices for the purpose of fixing the Market Energy Charge.

DEMAND EXCEEDANCE:

In addition to all other rates and charges, in each billing period in which Demand exceeds the Customer's maximum authorized demand, Customer will be assessed $150 plus, in each day an exceedance occurs, 1.5 times the applicable monthly demand charge on the amount by which the highest Demand in the day exceeded the maximum authorized demand. This charge is in addition to, not exclusive of, the District's rights to require additional protective measures, recover for damages sustained to the Electric Service Facilities, disconnect Service, terminate any Contract, or take any other remedial action available to recover losses and prevent future exceedances.

SECURITY DEPOSIT:

The security deposit will be based on the highest previous or projected monthly billed amount, multiplied by a factor of three (3). At the District's sole discretion, the District may increase or decrease the security deposit in accordance with Section 8 of the Utility Service Regulations.

INTERRUPTION OF SERVICE:

In exercising its discretion to interrupt service as described in the District's Utility Service Regulations, the District may prioritize interruption of service to loads on this rate schedule ahead of other loads. Except as may be specifically provided in a Contract, in the event that service is interrupted or fails by reason of accident or any other cause whatsoever, the Customer shall not be entitled any compensation or reduction in charges and the District shall not be liable for any damages for such interruption or failure, nor shall such failure or interruption be held to constitute a breach of Contract on the part of the District or in any way relieve the Customer from performing the obligations of the Customer's Contract. This limitation of liability includes all damages of any nature, including direct, indirect or consequential.

TAX ADJUSTMENT:

The amount of any tax levied by any city or town in accordance with R.C.W. 54.28.070 of the laws of the State of Washington, will be added to all charges for electricity sold within the limits of any such city or town.

SERVICE POLICY:

Service under this schedule is subject to the rules and regulations as defined in the District's Utility Service Regulations.

EFFECTIVE: February 1, 2024

EXHIBIT C

FINAL Rate Schedules 35 & 36 Update
Staff Report

August 2023

Public Utility District No. 1 of Chelan County
327 N Wenatchee Avenue
P.O. Box 1231
Wenatchee, WA 98807-1231
www.chelanpud.org

Contents

Executive Summary

In 2022, the District's Board of Commissioners directed staff to prepare a rate proposal to update rates and terms of service to data centers, which include cryptocurrency and non-cryptocurrency data processing and similar operations. This staff report is staff's response. Staff proposes adjustments to rates and terms of service for data centers operations as a means to incorporate lessons learned while continuing to mitigate the identified operational and financial costs and risks associated with serving these loads. The proposal includes changes to the rate classifications in Rate Schedule 35, *High Density Load*, (Schedule 35) and Rate Schedule 36, *Cryptocurrency processing; Blockchain processing; and Similar Loads*, (Schedule 36). Staff's recommendation is the product of years of experience serving these loads, lengthy fact finding by staff, public presentations by staff to the Board, and public input including input from data center customers.

In the initial adoption of Schedule 35 and subsequently Schedule 36, the District acknowledged both the uncertainty of actual costs to serve these new classifications of customers, and the need to act quickly to establish rates and terms of service. Over time, the behavior of these types of loads have validated the District's decision to act quickly. Additionally, over time, District's understanding of the costs and risks of serving these customers has grown and some load characteristics have changed. The need to mitigate against potential large volume and inconsistent load still exists. However, a moderate amount of consistent load does not pose a material risk to other rate classes. Staff's recommended adjustments to Schedule 35 and Schedule 36 include:

- Move server farms from Schedule 35 to Schedule 36 so all data centers are served through Schedule 36 regardless of whether they perform cryptocurrency-related data processing
- Changes to Schedule 35
    - Lower the size limit from 5 aMW to 3 MW to be consistent with Schedule 36
- Changes to Schedule 36
    - Blend production cost and market costs into energy rate and automatically adjust the ratio based on total load on the rate schedule
    - Update other energy charges
    - Update risk premium methodology
    - Add minimum monthly purchase obligation
    - Prioritize interruptability of rate class
    - Set a maximum capacity, on a substation basis

Staff proposes no changes to Schedule 35 other than revising the classification to exclude data centers and lowering the size limit to 3 MW.

This report provides staff's recommendations. Section 1 of this report describes the cost characteristics of data center loads as customers of the District and the need for rate action. Section 2 summarizes the criteria applicable to this classification and rate setting action. Section 3 describes the procedural history related to the rate recommendation. Section 4 explains staff's recommended change to the rate classification. Section 5 provides the cost analysis and rate design in support of staff's rate recommendation.

Summary of Staff's Recommendation

Staff's Recommended Rate Class Definitions:

High Density Load (Schedule 35) – This schedule applies to loads with an energy use intensity (EUI) of 250 kWh/ft2/year or more and with electrical loads up to and including 3 MW at a single Point of Delivery where:

- "Energy Use Intensity" or "EUI" means the annual kilowatt-hours of Energy usage divided by the operating space square footage used by the Energy consuming activity as determined by the District; and

When calculating the EUI, the District may make reasonable assumptions and projections as necessary to estimate Energy usage and square footage based on the Customer's application, data regarding similar operations, and other sources. An entity otherwise subject to this Schedule will be excluded from this schedule if the entity demonstrates to the District's reasonable satisfaction, or the District determines on its own initiative, that the energy use intensity (EUI) of the subject facility is less than 250 kWh/ft2/year.

Data Centers and Similar Loads (Schedule 36) - This Schedule applies to data centers and similar computing loads, regardless of the number of servers/processors, including those related to rack space rental, hosting services, cryptocurrency mining, blockchain, data processing or other loads having, in the District's determination, similar characteristics including any of the following: high energy use density, high load factor, need for more than routine alterations to the District's Electric Service Facilities in order to maintain safety, load that is portable and distributable, highly variable load growth or load reduction as an individual customer and/or in aggregate with similar customers in the District's service area, able to relocate quickly in response to short-term economic signals, high sensitivity to volatile commodity or asset prices, or part of an industry with potential to quickly become a large concentration of power demand in the District's service area. This Schedule does not apply to common computing loads typical in residences and in premises or businesses not primarily involved in data processing.

Summary of Staff's Recommended Schedule 36 Data Center Energy Rate (through 5/31/24):

Total load ≤ 10,000 kW	3.04¢ per kWh
Total load > 10,000 kW	3.04¢ per kWh blended with the Market Energy Charge in the ratio of 10,000 kW to the amount total load exceeds 10,000 kW. For example, if total load is 15,000 kW, the Energy Charge will be 3.04*(10/15) + Market Energy Charge*(5/15).

More detail is provided in staff's recommended rate schedules attached as Appendix A (Schedule 35) and Appendix B (Schedule 36).

Section 1 – Data Center Customers

Overview

In 2015-2016, the District undertook an effort to identify and classify a group of customers interested in service that was of a very different profile than any existing customer class. From this effort, the High Density Load (HDL) class was established and a new rate (HDL rate or Schedule 35) went into effect January 1, 2017. As the HDL customer class grew, the District gained a better understanding of their energy needs as well as a better understanding of the subsequent impact to the District's delivery and energy systems. The experience validated prior assumptions (e.g., profiles, mobility, energy use intensity) and identified areas needing additional measures (e.g., relation between cryptocurrency value and its electricity demand, equipment sizing and capacity needs for safe, reliable operation.)

In late 2017, a rapid increase in the value of the cryptocurrency bitcoin led to an equally rapid influx of inquiries and electric service requests ranging from a few kilowatts to a gigawatt. Most service requests come with expectations to be up and running in just a few months. As a public utility with about 51,000 electric customers and an average load forecasted at about 220 aMW for 2023, the potential for rapid increase affected the regular course of business and threatened the District's cost and financial models. Consequently, the Board adopted Schedule 36 in 2018, which explicitly focused on cryptocurrency. Schedule 36 included a rate based on the market price of energy in recognition of the costs and risks associated with potentially needing to serve a large and volatile new class of customers.

In 2022 and 2023, the market-based rate experienced large increases due to increases in wholesale energy prices. Schedule 36 customers expressed concern over the corresponding increases to rates. The Board responded by postponing increases, establishing a rate transition period, and directing staff to revisit the basis for the rate. Staff's proposal reflects lessons learned from years of cryptocurrency load. The threat of rapid load growth persists. Other utilities with similarly low rates have experienced significant and disruptive load growth from cryptocurrency and reacted through rate actions, policy changes, and moratoria on new services. In other words, as the staff reports for the 2016 and 2018 rate actions described, data center and cryptocurrency loads have the potential to drastically change the configuration of the District's transmission and distribution infrastructure and the way the District manages its power resource portfolio.

This section summarizes the reasons underlying staff's recommendations in this report.

Key Considerations for Data Center Reclassification

The 2018 Staff Report noted many characteristics shared between cryptocurrency loads and HDL loads such as server farms. This staff recommendation incorporates the findings in the 2016 [1] and 2018 [2] staff reports as adopted by the Board of Commissioners. New and updated characteristics are discussed below and are the driver for staff's recommendations included herein. Combining cryptocurrency and non-cryptocurrency data centers into the same rate class is principal classification change in this recommendation. The reasons are described below and in Section 4.

High Sensitivity to Volatile Commodity or Asset Prices

Spikes up or down in cryptocurrency prices directly result in a dramatic upswing or drop-off in demand for power from cryptocurrency miners. This sometimes rapid and always unpredictable change in markets and demand can require the District to buy or sell power to ensure it is matching the power

[1] In Resolution No. 16-14059, the Board adopted the HDL Staff Report as a basis for the HDL rate (Schedule 35).
[2] In Resolution No. 18-14287, the Board adopted the Cryptocurrency Staff Report as a basis for the cryptocurrency rate (Schedule 36).

supply with the cryptocurrency miners' fluctuating load.. In addition, the District is required to forecast and monitor load for energy market and balancing area requirements. The rapid change can have negative consequences to these operations as well.

Preceding the moratoriums established by the Board in December 2014 and in March 2018, a spike in the price of bitcoin led to a spike in requests to the District for new electricity service. Price volatility has continued. The price of bitcoin spiked again in 2021, topping out at over $64,000, which was more than ten times the price in 2019, then dropped by half six months later. The pattern is clear: higher cryptocurrency values lead to higher volumes of mining.[3]

The District has experienced data centers swapping between cryptocurrency and non-cryptocurrency processing with apparent fluidity. Price signals appear to have been a factor.

Potential to be Large Concentration of Power Demand

As described in the 2016 and 2018 Staff Reports, cryptocurrency data centers continue to pose a substantial risk because they can be a large concentration of power demand in industries exposed to volatile commodity prices. However, the large volume of load has not and may not materialize on the District's system. Staff recommends updating the energy rate for Schedule 36 to reflect the District's experience to date and the continuing risks associated with serving the customer class, while protecting against substantial and accelerated growth in the rate class.

For these reasons, staff recommends combining cryptocurrency and non-cryptocurrency data centers into the same rate class.

Cost Recovery through Rates

Schedules 35 was adopted in 2016 and designed for HDL loads. Schedule 36 was adopted in 2018 and designed for cryptocurrency loads. Since that time, staff's understanding has evolved and the subject industries have developed; the load characteristics experienced by the District, and thus the cost of serving, cryptocurrency and non-cryptocurrency data processing appear more alike than expected. A large influx of either type of data processing would still stress the District's hydroelectric resource portfolio, thus triggering the need to rely on substantial market purchases. The relatively modest and consistent data center load the District has experienced thus far have only had a moderate effect on the District's hydroelectric portfolio management. In addition to the current Schedule 36 energy rate, existing features of Schedule 36 have likely been effective in reducing the risk of load volatility within the class. Additional features proposed in this rate update are expected to further mitigate those risks.

Ongoing Monthly Rates

Staff does not recommend changes to the customer or delivery charges for Schedule 36 customers. These charges are based on the cost-of-service analysis performed during the initial development of the Schedule 35 HDL rate and previously adopted for Schedule 36 as well. The impact to the power delivery systems and customer service functions remains consistent across both Schedule 35 and 36 customers.

Staff recommends that the Board set a new energy rate for Schedule 36 data processing customers. This rate would be based on this same Schedule 35 cost of service analysis mentioned above as long as the total load in the rate class is below 10 MW. The Schedule 35 energy rate can be described as a cost of production-based rate. Staff also recommends that a market-based energy rate apply if total load exceeds 10 MW. As was the case with the last adopted Schedule 36 rate, the market-based rate would

[3] The cost of mining a cryptocurrency is the cost of computer hardware, power, and overhead. The earning of mining is the cryptocurrency. Increases in the price of bitcoin are supportive of increased mining and can also support increased power consumption to run the mining operations worldwide.

include other energy related charges that recover expected market costs, financial impacts, and increased risks to serve customers from market power. The market-based rate would be blended with the production-based rate proportionally to the amount the total authorized load exceeds 10 MW. As an example, if the total load is 15 MW, the rate would be the sum of 10/15 times the production-based rate plus 5/15 times the market-based rate.

Minimum Bill or "Take-or-Pay"

Staff recommends a take-or-pay approach to billing data center customers by applying a minimum bill for energy and demand. Including "take-or-pay" provisions in power contracts are becoming increasingly common within the industry, particularly for customers with high load factors, and are generally established with long-term, large load customers who present increased financial risks for the utility. In simplest terms, take-or-pay provisions protect the seller if the buyer refuses to take delivery of ordered goods. Applying this concept to a power contract or rate schedule, a take-or-pay provision would establish a consistent monthly demand and energy charge for the customer, i.e. a minimum bill amount. For example, a customer with an authorized demand of 2 MW would be billed as if its authorized demand of 2 MW is met each billing period. Specifically, staff recommends billing a minimum of 100% of the authorized maximum demand and 90% of the authorized energy usage. For system planning purposes, data centers are assumed to be running continuously. This means the full capacity of the energy needed to serve them is essentially dedicated to them whether they are using it or not. Therefore, charging for 100% of demand is appropriate. Data centers typically operate at a load factor of approximately 90%, which is a reasonable assumption for power supply planning purposes.

Financial Risk Mitigation- Energy take-or-pay provisions are intended to protect the utility in the event the customer's load operates below expected levels thus providing financial surety – particularly when the District purchases energy on the wholesale market to fulfill the customer's desired capacity. While the provision addresses risks for operating *below* capacity thresholds, customers would continue to be subject to all applicable Demand Exceedance charges and other applicable fees specified within the contract for surpassing approved demand limits.

Load Stability - Risks associated with cryptocurrency mining operations, as noted previously, include unproven sustainability in an unregulated industry that is subject to volatile commodity prices which can directly affect the customer's load behavior. Establishing a take or pay provision encourages customers to avoid rapid fluctuations on the system while "chasing" cryptocurrency prices or responding to changing energy market prices. Incentivizing customers to operate their load in a level manner puts less strain on the distribution system and supports system short and long-term planning strategies. In order to manage the distribution system, the District needs to assume high load factor customers will be operating consistent with their applied-for service all the time. Costs are incurred to operate the allocated distribution capacity and are not recovered if the load drops off part of the year due to customer maintenance cycles, low cryptocurrency prices, or some other temporary economic signal.

Term of Commitment

Staff recommends requiring a minimum of 60-day advance notice from a Schedule 36 customer desiring to terminate, reduce, or change service. Like the take-or-pay approach described above, requiring advance notice furthers the objective of ensuring commitment and predictability, and therefore cost recovery, from data centers. Staff considered requiring longer advance notice. Advance notice of twelve

months would better align with the District's resource planning cycle and therefore would significantly reduce the risk of needing to remarket excess power at a potential loss and on short notice. However, other features of the rate mitigate this risk, such as the market-price risk component of the risk premium described in Appendix C. Additionally, the District can require longer notice for loads over 3 MW by contract. Given the size of these customers and the other risk mitigations, staff concludes 60 days to be appropriate minimum advance notice for data center customers voluntarily terminating or reducing service or switching to a different rate schedule. The advance notice requirement would not apply to disconnection or termination of service by the District, which would be in accordance with District Utility Service Regulations, where unpaid bills are mitigated through security deposit requirements as noted below.

Credit Assurance (Security Deposit)

Staff recommends increasing the deposit requirement for Schedule 36 customers to three months. The Utility Service Regulations for non-residential customers require a security deposit of the highest monthly bill times a factor of two, representing the amount required to cover two months of bills for electricity service. This is necessary since the PUD provides electricity service prior to payment. Staff analyzed the risk to the District for non-payment of electricity service provided up to the point of disconnection based on the Utility Service Regulations. If a bill remains unpaid after 45 days from the date the bill was issued, the PUD can send notice of disconnect. If after 7 days following notice of disconnect, the bill remains unpaid and satisfactory payments arrangements have not been made, the District can disconnect electricity service. Since bills are issued at the first of the month for service the prior month, there is risk electricity service will be provided without payment for up to 82 days (30 + 45 + 7) on average, which leaves the District with 22 days of exposure that the Utility Services Regulations does not cover with its two-month security deposit requirement. Actual exposure could be longer than 22 days if the notice of disconnection and the actual disconnection do not occur on the earliest possible day, which is common as the District tries to work with the customer and as staff availability varies. Thus, staff is recommending a three-month security deposit for this rate class to better protect the District against uncollectible receivables, given its potential for customers being highly transient, particularly for cryptocurrency mining operations where profit margins are contingent on a volatile commodity in cryptocurrency.

Due to the nature of this rate class having a market-based energy rate component if the rate class load exceeds 10 MWs in total, Staff is also recommending that the District reserve the right, at its discretion, to require an increased security deposit that is commensurate with 3 months of the highest bill expected during the following 12 months after the energy price is reset. Additionally, customer deposit requirements for this rate class may be reevaluated from time to time based on customer payment experience, load volatility and growth, the total load on Schedule 36, and other facts and circumstances to ensure the District's risk and exposure to non-payment is reasonable.

Interruptability

Voluntary load reduction programs have gained popularity over the years with many utilities in the midwestern and southeastern states particularly when coupled with demand response price offerings. Periods of temporary curtailment can range from peak and off-peak periods, as well as "shoulder" periods when local loads are strained due to winter heating or summer cooling. Partnering with large customers who can quickly shed load presents opportunities for some utilities to serve peak demand

loading while postponing costs from new capital investments while also reducing strain on existing transformer banks.[4]

Some utilities also partner with large customers to allow the utility to maximize wholesale power revenue opportunities when market prices are at a premium in exchange for reduced rates for the participating customer(s). Advance notice and coordination of communicating equipment is a must for these programs to prevent utilities from shutting services down on a "whim" and to allow customers to prepare the equipment and operations.

Some data centers have expressed a willingness to temporarily shut down their servers in exchange for a reduced energy rate suggesting that the District could in turn sell their curtailed capacity on the wholesale market when prices are favorable. While the ability to interrupt service without compensation already exists pursuant to the District's Utility Service Regulations, staff believes there would not be sufficient value in interrupting load in response to market conditions at this time. The new equipment and expense required to support load shedding coordination, coupled by the relatively small size of current Rate 36 customers, would make it difficult to monetize the small amounts. Instead, staff recommends allowing District operational staff to prioritize interrupting service to Schedule 36 customers without compensation for system protection and load/Bulk Electric System (BES) reasons before interrupting service to other customers.

Upfront Capital Charge
Staff does not propose changes to the upfront capital charge for Schedule 35 or Schedule 36.

Demand Exceedance Charge
Staff does not propose changes to the demand exceedance charge for Schedule 35 or Schedule 36.

Uncertainty in Rate Development
Staff's recommendations in this report attempt to adjust rates for data centers to better align the rates with the cost of serving these customers so the District can continue to serve them in a reasonable manner over the long term. The adjustments are informed by the District's experience with providing service to these customers, the experiences of other utilities, and changes in data processing industries over time. The rate proposal balances the continuing desire to gather more data to gain a more complete picture of the cost characteristics of data center load before taking action, with the desire to set stable and predictable rates. Blending market-based energy rates proportionally to the total load within the class provides built-in adaptability by stabilizing rates if total data center load continues to be stable but protecting the District if it does not. In addition, the proposal reflects the continuing possibility of a rapid influx of data centers.

Despite the advancements in understanding data centers, certain additional data continues to be elusive that, if it had been available to staff, would have informed staff's recommendation. For example, staff has no way to accurately forecast the actual number and size of data centers that will be added to the District's system. Staff's recommended data center rate change, if adopted, may affect the growth rate of cryptocurrency load, but again there is no way to meaningfully forecast or test the effect without adopting the rate. Because the initial rate is lower than current Schedule 36, a significant increase in applications is possible. Moreover, cryptocurrency data processing applications correlate strongly with cryptocurrency prices, which continue to be volatile. Staff expects features of the rate to reduce the

[4] The non-wire alternative: ConEd's Brooklyn-Queens pilot rejects traditional grid upgrades | Utility Dive, published August 3, 2016. (https://www.utilitydive.com/news/the-non-wire-alternative-coneds-brooklyn-queens-pilot-rejects-traditional/423525/)

District's exposure to the risk of stranded transmission and distribution assets and to limit destabilizing effects that the classification may otherwise have on rates for other customer classes and on the District's hedging program. Because the proposed rate is low compared with the rates generally available on a national level, such rate may attract small data processing customers. However, substation limits are intended to mitigate risks of substation concentration for this rate class and curb accelerated growth that could otherwise challenge the District's substation planning standard.

The District retains the ability to modify any of the rate components as deemed appropriate by the Board.

Section 2 - Criteria for Classification and Rate Setting

The Board has the authority to create rate classes and to establish and modify rates. Classifications are made based on reasonable distinctions between customers and they may rest on narrow distinctions. Classification criteria typically relate directly to the cost of serving the load. For example, the quantity of power used, the seasonality of use, or the maximum demand at any given moment are directly related to the cost of serving the load. However, other reasonable factors may be used. For example, a type of business or power use with distinct load characteristics may have its own classification. This practice is common in the utility industry, and the District currently has such classifications (e.g., frost protection, street-lights, high-density load, cryptocurrency, direct current fast charging electric vehicles).

When setting a rate for a rate class, utilities consider, amongst other things, the impact to the utility and all its customers, the value of the service rendered, fair compensation and return on investment to the utility, and the long-term financial stability of the utility. The manner in which rates are fixed must not be arbitrary. Rates need not, and in fact cannot, be set to a mathematical certainty. Rather, rate setting is a legislative function in which reasonable considerations and philosophies are applied to generally accepted accounting principles. The District, in compliance with RCW 54.24.080 and if it has revenue obligations outstanding, is required to establish, maintain, and collect rates or charges for electric energy and water and other services, facilities, and commodities sold, furnished, or supplied by the District. The rates and charges must be fair, nondiscriminatory and adequate to provide revenues sufficient for the payment of the principal of and interest on such revenue obligations for which the payment has not otherwise been provided and all payments which the District is obligated to set aside in any special fund or funds created for such purpose, and for the proper operation and maintenance of the public utility and all necessary repairs, replacements, and renewals thereof.

By Resolution No. 80-6286 (April 28, 1980), the District adopted certain standards related to ratemaking under Section 111(d) of the Public Utility Regulatory Policies Act ("PURPA"), 16 U.S.C. § 2621(d). By Resolution No. 18-14256 (August 6, 2018), the District adopted additional procedures related to ratemaking that superseded some of the 1980 standards. These resolutions include procedures and ratemaking considerations associated with the process of ratemaking, including use of a cost-of-service analysis. Section 3, *infra*, contains the procedural history of the ratemaking process to date. The cost of service is addressed in Section 5, *infra*. The Board may waive the standards and procedures in the resolutions when appropriate.

Staff's proposed reclassification of server farms and adjustments to rates meet the District's criteria for classification and rate setting. Setting rates that reflect a classification's cost characteristics furthers the District's ability to ensure it can serve this new type of load in a just and reasonable manner and consistently with prudent long-term planning, including protection for other customers.

Section 3 - Notice and Procedural History

Commission Meetings and Public Notices

- **March 21, 2022** - Board presentation to address consideration of options to customers' requests for transition plan from Rate 35 High Density Load to Schedule 36 Cryptocurrency
- Deferred market energy rate adjustment from April 1 to June 1 while options are considered by the board
- **May 16, 2022** – Recommendations to allow transition plan for Rate 36 customers. Decision deferred until a future meeting date
- **June 6, 2022** – Resolution establishing transition plan for loads transitioning from Rate 35 to Rate 36
- **March 20, 2023** – Update on review process. Motion to defer annual market energy rate adjustment from April 1 to August 1, 2023 allowing staff to complete the review process.
- **July 24, 2023** – Public presentation of rate proposal to Board
- **July 25-August 4, 2023** – Public notice, including legal notice, of rate hearing in newspapers, direct mail, social media, and on the District website
- **August 7, 2023** – Public rate hearing including public comment

Public Comments

Information meetings and rate hearings provide opportunities for the members of the public to voice their opinions, ask questions, and express support for or opposition to proposed action. The District received written and verbal comments from members of the public during public meetings and outside public meetings.

Section 4 – Classifying Data Centers and Similar Loads

Defining a rate class is fundamental to a rate. Staff's proposed classification would move server farms and other data processing based loads from Schedule 35 to Schedule 36, where they would join cryptocurrency. Staff crafted the new classifications based on its investigation and the knowledge gained over years of experience with inquiries from and service to data centers. The following considerations and findings form the basis of staff's recommended change to classification.

Key Considerations and Findings Regarding the Classification

Identified Characteristics and Costs

Since the Board initially adopted Schedule 35 in 2016 in reaction to rapid growth in server farm loads, data processing industries have continued to evolve. The Board adopted Schedule 36 in 2018, which focused on cryptocurrency because it had become apparent that cryptocurrency-related data processing was uniquely driving a dramatic increase in activity for the District and for other electricity utilities. In recent years, as the cryptocurrency industry and other data processing industries have continued to develop, distinctions between cryptocurrency and non-cryptocurrency data processing has become less apparent, particularly with respect to the smaller sized data centers subject to Schedule 35 and 36. In fact, some premises served by the District have seamlessly switched between hosting cryptocurrency and non-cryptocurrency data processing. Moreover, the shrinking differences have increased the difficulty of distinguishing between cryptocurrency and non-cryptocurrency for purposes of applying the appropriate classification. In sum, although distinguishing cryptocurrency from other data centers made sense in 2018, staff now recommends combining all data centers into one rate class because the cost characteristics, including various risks, have become more alike. Even though Schedule 35 was originally triggered by the need to provide sustainable service to server farms, and staff now recommends serving all server farms on Schedule 36, Schedule 35 still fills a role in the District's rate schedules. Schedule 35 was originally designed to cover other types of high density loads with the cost characteristics described in the 2016 Staff Report. It continues to be appropriate for such high EUI loads.

Similar Classifications in the Utility Industry

The District adopted a "High Density Load" rate class in 2016 due in part to growth in bitcoin mining in Chelan County. In August of 2018, the Public Utility District of Grant County, Washington adopted a rate class for cryptocurrency miners based on similar characteristics. Grant PUD recently amended Rate Schedule 17 - Evolving Industry to specifically identify cryptocurrency operations as an "evolving industry" due to business and regulatory risks demonstrated.[5] In March 2018, the Public Utility District of Benton County, Washington adopted a policy for cryptocurrency customers in response to concerns about the distribution system safety and reliability. In February 2022, Benton PUD created a new Large Electricity Intensive Load (EIL) Rate 35[6] for cryptocurrency and server farm operations. This new rate requires a power sales contract and was developed to protect other customers from additional rate pressure caused by larger EIL loads.

[5] January 10, 2023 Grant PUD Commission Packet amending Rate 17 Evolving Industry. (https://www.grantpud.org/block/documents/63b75ab8b2cad-2023-01-10-commission-meeting-packet.pdf)

[6] February 22, 2022 Benton County PUD Commission Packet adopting Rate 35. (https://www.bentonpud.org/getattachment/Board-Meetings/2022/2022-02-22/Commission-Packet-2022-02-22.PDF.aspx?lang=en-US&ext=.pdf)

Policies for addressing added exposure to both operational and financial risks that cryptocurrency type loads are also common in other areas outside of Washington State. In a recent report published by the American Public Power Association (APPA), actions that other utilities are taking to address this customer base were summarized.[7] The City of Hamilton, Ohio, recently negotiated a contract to support a container-based crypto load of 20 MWs that includes a fixed cost for the first 10 MWs of energy, and a power cost adjustment for the remaining capacity. Stanton County Public Power District, Nebraska, anticipates future demand of up to 70 MW to service crypto-mining loads and has rates and policies very similar to those of Chelan PUD. Key elements included in the rate structures and contracts across the board align with the recommended paths herein such as interruptible loads, fully funded customer capital investments, and collateral requirements to mitigate load volatility in response to cryptocurrency market conditions.

Substation Availability

Staff recommends that new data center load be allowed only where it would not increase total substation usage above 70% of its capacity and be limited to a maximum of 3 MW per substation for the following reasons.

The District's substation planning standards are designed to ensure, as organic load growth occurs on the electrical system, new substations are budgeted, designed, procured, and constructed to meet demand and maintain reliability for the District's customers. The planning standard specifies that once a substation reaches 80% of remaining power transformer capacity we begin planning for an additional substation. Based on historical organic load growth between 1% to 1.5% we generally have sufficient time to procure property, design, and construct new substations before the existing substation reaches or exceeds 100% of its capacity. An overloaded substation poses a significant reliability risk to customers and shortens equipment life. Cryptocurrency operations, server farms, data storage centers and other similar loads with high volume power consumption and high load factors can prematurely diminish available capacity in a given substation and move the substation to full load much earlier than planned and can decrease asset life caused by continuous high demand. This would result in the District needing to take on reliability risk and accelerate property acquisition, design, and construction to restore sufficient capacity for organic load growth. Preventing new data center loads from causing a substation to exceed 70% of the remaining capacity will reduce the risks and costs of the District being forced to respond prematurely to unplanned substation capacity deficiencies. After a substation reaches 70%, no additional data center or other similarly situated loads would be allowed on that substation. Moving load from substation to substation for the purposes of making capacity available for data centers will not be allowed under the District's application process.

The majority of the District's substations work in a network configuration where they are joined by one or more distribution feeder. This is so that in an event where a substation power transformer is lost, the adjacent substations and distribution feeders can pick up all or a portion of the customers on the substation experiencing the failure. During these events short-term high loads can occur on the adjacent substations and feeders. Transferring large loads such as data centers to an adjacent substation during an unplanned event requires careful planning and analysis to avoid complications. The risks include inability to transfer all customers, critical customers, or in some cases overloading adjacent substation transformers and feeders which could lead to cascading system failures. For these reasons it is

[7] April 13, 2023 Managing New Electric Loads – Cryptocurrency Mining and Cannabis Facilities, APPA. (https://www.publicpower.org/system/files/documents/Managing-New-Electric-Loads-Cryptocurrency-Mining-Cannabis-Facilities.pdf)

important to limit data centers to a combined 3 MW (peak) on each substation. The 3-MW limitation per substation is an independent threshold and in addition to not allowing new data center load to cause a substation to exceed 70% of its capacity threshold.

Reduce Contract Threshold for Schedule 35 to 3 MW

In recommending a 3 MW contracting threshold for Schedule 36, the 2018 Staff Report noted the benefit of addressing larger customers' unique requirements and characteristics, including infrastructure upgrades, through special contracts. For the same reasons, staff recommends lowering the Schedule 35 threshold to 3 MW to align with Schedule 36.

Staff's recommended rate classifications appear in Appendix A (Schedule 35) and Appendix B (Schedule 36.

Section 5 – Cost of Service and Design of Data Center Rate

Introduction

In 2016, the District established a High Density Load (HDL) rate class based upon the Cost of Service Analysis (COSA) completed at that time, which was developed in 2008 and updated by the Strategic Financial Planning department. Due to a lack of historical data on HDL customers at that time staff relied partly on the COSA attributed costs of the two most similar customer classes, the commercial and industrial classes. To develop the cryptocurrency rate in 2018, staff leveraged the COSA and rate design used for the HDL rate for the base (Customer) component and the demand (Delivery) component. The supply (Energy) component was based upon the cost of purchasing market energy rather than the District's cost of generation. With sufficient usage and load data associated with HDL and Cryptocurrency customers now available, the COSA has been updated to categorize the costs of these customers as their own customer class. The allocation methodologies used within the COSA to categorize costs for the customer, delivery, and supply components have not materially changed since the initial HDL effort was completed in 2016. The updated revenue requirements, including the supply component based on the cost of generation for the HDL class, are materially in line with the results leveraged for the initial HDL rate development in 2016. Details and supporting calculations of the COSA performed for the HDL rate can be found in the HDL Staff Report. This section describes the principles and methodologies used to design the approved HDL and cryptocurrency rates in 2016 and 2018 and which are the basis for the proposed Schedule 36 rates. It includes an overview of the COSA methodologies used to functionalize, categorize and allocate the District's revenue requirements. It also includes a description of the methodologies used to structure the rate based on the COSA.

General Rate-setting Guidelines and Procedures

Developing rates that meet all the identified objectives and policies is a complex process. Recent COSA efforts have identified several general principles and objectives that rates should reflect or further:

- Fair, Equitable & Non-Discriminatory
- Revenue Stability & Sufficiency
- Cost Based
- Continuity in Philosophy
- Incorporate Strategic Objectives
- Conservation & Efficient Usage
- Simplicity in Administration & Understanding
- Major Shifts Adjusted Over Time

General rate-setting objectives often conflict with each other, so the resultant rate depends in part on how the District balances these objectives. The District's COSA and rate setting process employ industry accepted methodologies as well as specific methodologies adapted as needed for the special characteristics of the District and the costs it incurs.

Cost of Service Analysis

The Strategic Financial Planning department manages the District's COSA on an ongoing basis. Staff last presented the District's COSA to the Board in 2008 (the "2008 COSA"), when the Board approved the reasonableness of its calculations. The 2008 COSA informed the design of current electricity rates. Since 2008, some aspects of the methodology in the COSA have been updated by Strategic and Financial Planning to meet changing circumstances. These changes include the implementation of new long-term power contracts, financial policy changes, changes to the District's wholesale market hedging program,

public power benefit actions, and enhanced financial forecast modeling to mention a few. In addition, a new rate class has been added for HDL/cryptocurrency customers as well as for electric vehicle fast charging stations. The 2008 model, with the above-mentioned changes, is updated on an ongoing basis with current financial results and forecasted cost information. The three main steps in the COSA are to functionalize (assign revenue requirements to customer-related, delivery-related, or supply-related components), categorize (divide functionalized expenses among customer classes) and allocate (assign miscellaneous costs including District overheads) costs and revenues among the various customer classes. This process incorporates past practice, industry standards and the expertise and direction provided by key District employees to produce the cost-of-service result.

The initial steps of functionalization and categorization are closely related and have been combined in the District's cost of service supporting documentation. These combined steps involve assigning the revenue requirement among the general categories of supply-related, delivery/collection-related and customer-related (also referred to as energy, demand and basic, respectively) by customer class. This categorization closely resembles the existing structure of the District's financial accounting system and the financial forecasting system but does require the application of some methodologies to properly assign or allocate some components of the revenue requirements. The general basis of the methodologies used in determining how costs were allocated and revenue requirements categorized are detailed in the 2016 HDL Staff Report along with the corresponding results.

Functionalizing Costs into Customer, Delivery, and Supply Components

Customer (Basic) Cost Component - Customer costs are costs that vary primarily by the number of customers in a customer class and include customer billing, collections, records, meter reading, service, etc. along with a proportionate share of the District's administrative and general (A&G) costs that support all the District's activities.

Delivery/Collection (Demand) Cost Component - Delivery costs include the costs of transmission and distribution services, including a proportionate share of A&G and depreciation, and a rate of return on the District's investment in transmission and distribution facilities serving the customer class. These costs are generally driven by the maximum demand requirement imposed by the various customer classes and customers.

Supply (Energy) Cost Component – This cost category is often referred to as "energy" costs. Supply costs include internal and external power purchases[8] and activities directly related to acquiring power to serve the customer, along with a proportionate share of A&G costs. These costs are primarily driven by the actual amount of electricity consumed by customers in each class.

The COSA methodologies for assigning of the three cost components have not materially changed since adoption of the HDL rate in 2016 and are detailed in the HDL Staff Report.

The other energy charges include transactional costs directly associated with the purchase of energy, financial impacts, additional risk exposure, costs of administration of the District's energy portfolio, and costs of the provision of scheduling and other ancillary services. The other energy charges are summarized in Appendix C.

Categorizing Costs into Rate Classes

Once the functionalization of costs has been completed, various methodologies are used to assign or "categorize" these cost components among the various rate classes and rate components. Rate classes

[8] In the District's internal accounting, the District treats power from the District's generating resources used by the District's retail system as if the retail system purchased the power from the District's resources.

include residential, commercial, industrial and other defined groups of customers that have similar service requirements. The methodologies used to accomplish the allocations are summarized below with supporting analysis in the HDL Staff Report. Note that the District's current division among customer classes is based in part on differences in total electricity (energy) use and the rate of use (demand).

The data center revenue requirement for the basic (Customer) component, the demand (Delivery) component and supply (Energy) component are all derived from the calculated requirements of the HDL class from the HDL rate adopted in 2016, except that a unique demand component for residential customers was established in the cryptocurrency rate adopted in 2018. The revenue requirement includes operating activity and the offsetting revenue associated with customer contributions in aid of construction as a credit to gross capital investment requirements.

Basic (Customer) Cost Component and Demand (Delivery) Cost Component – No changes are proposed to the basic cost component or the demand cost component. Background can be found in the 2016 and 2018 Staff Reports.

Energy (Supply) Cost Component – The costs assigned to this component are directly associated with customer's total consumption or use of the service, and are allocated based on the measured energy usage (kWh) of each of the customer classes, including line losses.

Design of the Data Center Rate

Energy (Supply) Cost Component – Schedule 36 customers will be served at a cost of production rate (the same rate as Schedule 35) until the total load on the rate schedule exceeds 10 MW. When total load exceeds 10 MW the rate will be blended with the first 10 MW at the cost of production rate and incremental MWs above 10 MW at a market rate fixed annually based on the Intercontinental Exchange (ICE) Mid-Columbia forward prices. Other energy charges will be included in the market rate. For example, if the total load is 15 MW, the energy rate would be [10/15 times the cost of production rate plus 5/15 times the market rate]. The District has so far found that loads in data centers at current levels below 10 MWs appear to be manageable with respect to cost and risk. In addition, new limits on infrastructure recommended with this rate change will mitigate certain risks even with the cost of production rate. The rationale for the 10-MW threshold is further described in the Risk Premium section in Appendix C. Loads in this rate class larger than 3 MW require a contract which will establish the rate and may count towards the total load of the class if their rate is based on the rate for loads under 3 MW and unless their special contract provides otherwise.

Other Energy Charges	
Charge	Charge per kWh
Carbon Free	0.600¢
Resource Adequacy/Capacity	0.978¢
Index Physical	0.429¢
Allocated Overhead	0.150¢
Direct Overhead (incremental resource time)	0.100¢
Scheduling & Ancillary Services (load following, reserves, voltage control)	0.129¢
Credit Premium	0.011¢
Risk Premium	0.527¢
Overhead Tax	0.175¢
Total Other Energy Charges	**3.099¢**

Under Schedule 36, customers at or above 3 MW require a contract with the District to establish the rate and address any special circumstances and conditions applicable to the Customer's needs and to address any terms and conditions considered appropriate by the District, including the manner and volume which energy will be purchased and delivered. Staff is not proposing changing the 3-MW contract threshold.

Summary of Staff's Recommended Schedule 36 Data Center Energy Rate for loads up to 3 MW (through 5/31/24):

Total load ≤ 10,000 kW	3.04¢ per kWh
Total load > 10,000 kW	3.04¢ per kWh blended with the Market Energy Charge in the ratio of 10,000 kW to the amount total load exceeds 10,000 kW. For example, if total load is 15,000 kW, the Energy Charge will be 3.04*(10/15) + Market Energy Charge*(5/15).

More detail is provided in staff's recommended rate schedules attached as Appendix A (Schedule 35, in part) and Appendix B (Schedule 36).

Upfront Capital Charge

Staff is not proposing any changes to the upfront capital charge.

Demand Exceedance Charge

Staff is not proposing any changes to the demand exceedance charge.

Appendix A Availability of Schedule 35: High Density Load

DRAFT High Density Load

Rate Schedule 35

AVAILABILTY:
This schedule applies to loads with an energy use intensity (EUI) of 250 kWh/ft2/year or more and with electrical loads up to and including 3 MW at a single Point of Delivery, excluding Schedule 36 loads, where:

- "Energy Use Intensity" or "EUI" means the annual kilowatt-hours of Energy usage divided by the operating space square footage used by the Energy consuming activity as determined by the District; and

When calculating the EUI, the District may make reasonable assumptions and projections as necessary to estimate Energy usage and square footage based on the Customer's application, data regarding similar operations, and other sources. An entity otherwise subject to this Schedule will be excluded from this schedule if the entity demonstrates to the District's reasonable satisfaction, or the District determines on its own initiative, that the energy use intensity (EUI) of the subject facility is less than 250 kWh/ft2/year.

Service under this schedule may require a power sales Contract between the Customer and the District prior to connection of service. Changes in Load, as defined in Utility Service Regulation 41, will require a new service application to be submitted to the District to evaluate the impact of that changed load to existing Electrical Service Facilities.

Customers subject to the terms and conditions of Schedule 35 must meet the following characteristics:

- Be served at one Premise through a single Point of Delivery as defined in the District's Service Regulations;
- Be in compliance with Chapter 296-46B WAC electrical safety standards, administration and installation; and
- Maintain satisfactory Power Factor determined in Schedule 24.

Customers with multiple locations and Energy loads will not be aggregated for billing purposes unless the District, in its sole discretion, determines the Customer is circumventing the 3-MW Energy cap to meet the load requirements of a common Premise. A Customer with measured total connected loads greater than 3 MW may be required to be served under Rate Schedule 4.

OTHER SECTIONS OF RATE SCHEDULE 35 REMAIN UNCHANGED.

Appendix B Rate Schedule 36: Data Centers and Similar Loads

DRAFT Data Centers and Similar Loads

Schedule 36

AVAILABILITY:

This Schedule applies to data centers and similar computing or data processing loads, regardless of the number of servers/processors, including those related to rack space rental, hosting services, cryptocurrency mining, blockchain, data processing or other loads having, in the District's determination, similar characteristics including any of the following: high energy use density, high load factor, need for more than routine alterations to the District's Electric Service Facilities in order to maintain safety, load that is portable and distributable, highly variable load growth or load reduction as an individual customer and/or in aggregate with similar customers in the District's service area, able to relocate quickly in response to short-term economic signals, high sensitivity to volatile commodity or asset prices, or part of an industry with potential to quickly become a large concentration of power demand in the District's service area. This Schedule does not apply to common computing loads typical in residences and in premises or businesses not primarily involved in data processing.

This rate schedule is available throughout the District's service area with the exception of the Stehekin area and new or expanded service in the areas north and northwest of Leavenworth served by the Anderson Canyon-Summit transmission line and with the further exception of locations that would cause the serving substation to exceed 70% of design capacity or the total load under this rate schedule served by a substation to exceed 3 MW.

Service under this schedule requires a power sales Contract between the Customer and the District prior to connection of service. Changes in Load, as defined in Utility Service Regulation 41, require a new service application to be submitted to the District to evaluate the impact of that changed load to existing Electrical Service Facilities.

Customers subject to the terms and conditions of Schedule 36 must meet the following characteristics:

- Be served at one Premise through a single Point of Delivery as defined in the District's Service Regulations;
- Be in compliance with Chapter 296-46B WAC electrical safety standards, administration and installation; and
- Maintain satisfactory Power Factor determined in Schedule 24; and
- Agree to provide a minimum 60-days advance notice of termination, reduction or change of service.

Customers with multiple locations and Energy loads will not be aggregated for billing purposes unless the District, in its sole discretion, determines the Customer is circumventing the size cap to meet the load requirements of a common Premise. A Customer with measured total connected loads may be required to be served under the rates and terms applicable to such total size.

UPFRONT CAPITAL CHARGE:

Prior to approval of service or increase in capacity, Customers to be served under this Schedule must pay an Upfront Capital Charge based upon the requested size of the new or increased amount of electric load. The Upfront Capital Charge does not apply to load amounts approved by the District prior to the

effective date of this Schedule where the load is transferred onto this Schedule as of the effective date of the Schedule. Current amounts are included in the District's Fees and Charges schedule. Additional state and local taxes may apply. Additional charges may apply, including Line Extension costs.

SERVICE OVER 3 MW:

Service will require a Contract between the Customer and the District prior to connection of Service that will address any special circumstances and conditions applicable to the Customer's needs. Contracts will establish the rate and address any terms and conditions considered appropriate by the District, which may include but are not limited to scheduling, maintenance and decommissioning of infrastructure, load balancing, ancillary services, transactional costs, security, and financial risk. **CHARACTER OF SERVICE:**

Service to be furnished under this schedule may be either:

- Three phase, sixty hertz alternating current at primary voltage, or
- Secondary power single phase, three phase or four wire three phase, 60 cycle, alternating current at available phase and voltage up to 1 MW.

RATES - 3 MW AND LESS:

Basic Charge (per month):	**6/1/2023**	**6/1/2024**
Up to 300 kW	$150	$155
300 kW to < 1 MW	$630	$650
1 MW to ≤ 3 MW	$970	$995
Monthly Demand Charge, Non-Residential (per KW per month):	$6.20	$6.40
Monthly Demand Charge, Residential (per KW per month):	$16.40	$16.85
Energy Charge:	3.04 ¢/kWh*	
Upfront Capital Charge:	Per kW of new or expanded Electric Service under this schedule. Amount of upfront capital charge is set forth in the District's Fees and Charges Schedule	

*** The effective Energy Charge is recalculated at least annually in accordance with the provisions of this Rate Schedule 36. Visit chelanpud.org or call (509) 663-8121 for the current effective Energy Charge. In the event of conflict, the Energy Charge Blending formula below will control.**

RESIDENTIAL:

For purposes of the Demand Charge under this rate schedule, residential means premises located in areas of the distribution system that have been designed and constructed for loads with residential characteristics, such as high load diversity and low load size.

BILLING DETERMINANTS:

The billing determinant (in kW) for the Monthly Demand Charge is the greater of the Customer's maximum authorized Demand or the measured demand adjusted for Schedule 24, Power Factor. The billing determinant (in kWh) for the Energy Charge is the greater of the Customer's (a) maximum

authorized Demand multiplied by the number of hours in the Billing Period multiplied by 0.9; or (b) Energy usage in the Billing Period.

ENERGY CHARGE BLENDING:

Total load on rate schedule	**Energy Charge** (¢/kWh)
≤ 10,000 kW	Production Energy Charge: 3.04 ¢/kWh through 5/31/2024, 3.13 ¢/kWh on and after 6/1/2024
> 10,000 kW	A blend of the Production Energy Charge (PEC) and the Market Energy Charge (MEC) using the following ratio, where total load (TL) is in kW: $Energy\ Charge = \frac{10{,}000kW}{TL} * PEC(¢/kWh) + \frac{TL - 10{,}000kW}{TL} * MEC(¢/kWh)$

Total load is the sum of the maximum authorized demand of all loads expected to be taking service under the rate schedule during the upcoming 12-month Market Energy Charge period described below. Loads will be expected to be taking service if they are currently taking service or if they have applied for service and made substantial commitments towards commencing service prior to the end of the upcoming 12-month Market Energy Charge period. Loads greater than 3 MW that contract for an energy charge other than the Blended Energy Charge will not be counted towards the total load for purposes of rate blending unless otherwise specified by contract.

The expected total load will be reset annually as of the date the Market Energy Charge is fixed. The District reserves the right to reset the total load at any time, provided that the District will provide affected customers at least 60 days advance notice before an out-of-cycle reset goes into effect.

MARKET ENERGY CHARGE:

The Market Energy Charge will be fixed as of February 1 of each year by the District at the average flat price of the Mid-C Peak and Off-Peak Futures as published daily by the Intercontinental Exchange (ICE) for the 12-month period starting on June 1 plus a 6% administrative fee and plus 3.10¢/kWh). If ICE futures are not published on February 1, they will be fixed as of the next following date they are published. If ICE Mid-C Peak and Off-Peak Futures cease to be published, the District, in its reasonable discretion, may select a replacement source of forward prices for the purpose of fixing the Market Energy Charge.

DEMAND EXCEEDANCE:

In addition to all other rates and charges, in each billing period in which Demand exceeds the Customer's maximum authorized demand, Customer will be assessed $150 plus, in each day an exceedance occurs, 1.5 times the applicable monthly demand charge on the amount by which the highest Demand in the day exceeded the maximum authorized demand. This charge is in addition to, not exclusive of, the District's rights to require additional protective measures, recover for damages sustained to the Electric Service Facilities, disconnect Service, terminate any Contract, or take any other remedial action available to recover losses and prevent future exceedances.

SECURITY DEPOSIT:

The security deposit will be based on the highest previous or projected monthly billed amount, multiplied by a factor of three (3). At the District's sole discretion, the District may increase or decrease the security deposit in accordance with Section 8 of the Utility Service Regulations.

INTERRUPTION OF SERVICE:

In exercising its discretion to interrupt service as described in the District's Utility Service Regulations, the District may prioritize interruption of service to loads on this rate schedule ahead of other loads. Except as may be specifically provided in a Contract, in the event that service is interrupted or fails by reason of accident or any other cause whatsoever, the Customer shall not be entitled any compensation or reduction in charges and the District shall not be liable for any damages for such interruption or failure, nor shall such failure or interruption be held to constitute a breach of Contract on the part of the District or in any way relieve the Customer from performing the obligations of the Customer's Contract. This limitation of liability includes all damages of any nature, including direct, indirect or consequential.

TAX ADJUSTMENT:

The amount of any tax levied by any city or town in accordance with R.C.W. 54.28.070 of the laws of the State of Washington, will be added to all charges for electricity sold within the limits of any such city or town.

SERVICE POLICY:

Service under this schedule is subject to the rules and regulations as defined in the District's Utility Service Regulations.

EFFECTIVE: **TBD**

Appendix C Other Energy Charges

Other Energy Charges			
Charge	Rate	Description	Methodology
Carbon Free, I-937, and Climate Commitment Act ("CCA") Compliance	.600¢/kWh	Cost to the District associated with the Clean Energy Transformation Act ("CETA") compliance, cost to the District associated with the I-937 compliance, cost to the District associated with CCA compliance	Market adder for Carbon free product used as a baseline cost for product to meet all programs
Resource Adequacy ("RA") / Capacity	.978¢/kWh	Cost to the District associated with firm energy and capacity to meet requirements for RA compliance	Cost of adder for RA addendum to WSPP Sched C product and also the capacity to cover load plus the planning reserve margin.
Index Premium for Physical Product	.429¢/kWh	Cost of purchasing physical index energy from the wholesale market	Estimates based on index premiums for physical product in the wholesale market at various terms (e.g., day ahead, next month)
Credit Premium	.011¢/kWh	Charge to use the District's credit capacity with other entities.	Estimates based on cost of posting line of credit to cover market purchases
Risk Premium	0.527¢/kWh	Covers incremental financial costs and risks associated with market purchases, market power availability and data centers being transient in nature, subject to regulatory uncertainty, and having unpredictable growth and concentration.	Discussed in detail below
Allocated Overhead	.150¢/kWh	Recovery of costs directly associated	Five-year average of the energy portfolio

		with managing the District's energy portfolio along with a proportionate share of A&G costs that are included in the supply (energy) component of the cost of service.	management costs and A&G included in the supply component of the cost of service.
Direct Overhead	.100¢/kWh	Recovery of incremental resource time and direct overhead costs anticipated to serve data center loads	Estimated incremental resource time required in the areas of customer service, energy planning and trading, credit & risk, billing and legal
Scheduling & Ancillary Services	.129¢/kWh	Recover costs of scheduling, regulation and load following, spinning and operating reserves, and reactive supply and voltage control, etc.	Estimated incremental resource time required for scheduling power. Estimated costs of providing ancillary services of regulation and load following, spinning and operating reserves, and reactive supply and voltage control.
Overhead Tax	.175¢/kWh	State Utility & Privilege Taxes	6% of revenues collected from other energy charges

Risk Premium ($5.27/MWh or .527¢/kWh)

Data processing and cryptocurrency mining and their unique load requirements and characteristics present the District with many challenges, risks and uncertainties that are not present in the more traditional and predictable loads for commercial and industrial businesses and residential homes. However, the District has learned a great deal about this load class since Schedule 36 was implemented that is informing development of an energy rate revision that is more reflective of the District's previous experience and current conditions. The utility business model requires investments in long-lived assets and infrastructure to serve ratepayers in a sustainable reliable manner, the cost of which the utility recovers over generations through effective rate design and predictable revenue streams. The District's historical local load requirements and growth patterns have been very predictable with relatively small growth year over year. This has allowed the District to prudently and systematically plan and invest in transmission and distribution assets, protect the revenue streams offered by surplus generation through

hedging strategies, reliably serve its customer owners and ratepayers with low rates, and effectively meet its strategic plan objective to do the best for the most for the longest. Although the cryptocurrency rate was established in 2018, it is still relatively new, has unproven sustainability and is currently an unregulated industry that is supported by a volatile commodity value generated by transient machines, which effectively does not fit the traditional utility model, thus continues to create new risks, exacerbates existing financial and operational risks, and causes uncertainty in load forecasting, revenue predictability and forward infrastructure and asset planning that are all prudently considered in the energy rate revision and added infrastructure limits and energy thresholds. However, given that the District has not experienced significant load growth for either data processing loads or cryptocurrency mining since the original rate was developed and has not materially realized the financial and operational risks to date that had significant potential to occur, staff is recommending a blended and proportionate energy rate that is based on cost of production up to a 10 MW threshold and a market-based energy rate for load above the 10 MW threshold, The market-based portion of the energy rate would still include an adder that represents other energy related costs, however staff is recommending a risk premium revision commensurate with the market-based portion of the energy rate and updated with consideration of current market conditions and the District's current financial position and credit rating. Staff recommends that this energy rate revision continue to include a risk premium to mitigate the risks and uncertainty associated with this specific rate class and to help protect other rate classes from unintended consequences that could harm District operations or financials.

The data processing and cryptocurrency industry exposes the District to risks that are difficult to quantify or ascertain the likelihood of occurrence given the effective newness of this industry and behaviors that may become more known over time as the industry matures. The list of risks identified specifically in the 2018 Staff Report is not exhaustive and still apply, thus are recognized as significant uncertainties that are factored and considered in the development of the proposed changes to this rate class, and in part, are mitigated through introduction of substation loading and load limits to mitigate risk of accelerated growth, load concentration and to protect infrastructure. Take or pay provisions to encourage predictable load and provide predictable revenue, elevated credit assurances protect District's financials and address transient risk, and the risk premium and other energy charges protect the District from market-based risks and added costs from market power purchases. It should be noted that time will test the effectiveness of the energy rate modifications, but subsequent added provisions in the rate class as introduced and cited above further mitigate the known risks for this rate class and one of the drivers in the reduction of the risk premium. Refer to the 2018 Staff Report for descriptions of those risks, along with more detailed explanations below regarding the Risk Premium included in the other energy charges noted above.

Risk estimation is not a precise discipline and often requires that variables and assumptions are developed based on professional judgement and deliberation that can change over time as facts and circumstances change. The assessment of risk under novel circumstances involves essentially unbounded variables. It thus requires a high degree of judgment. Data centers – which are unique in terms of load characteristics – continue to rapidly evolve and continue to lack a meaningful track record from which to make long-term assumptions based on the District's experience since the Schedule 35 and 36 rate class were initially developed. For example, it is within reason to predict that the District will be faced with additional requests for incremental load beyond typical organic growth. And it is also reasonable to predict new applications will continue to be sparse. And it is foreseeable that the District could see a rapid influx of data centers, followed by sudden departure of all of it. Some of the key uncertainties are volatile cryptocurrency prices, minimal governmental regulation of the industry, competition amongst miners, comparative electricity prices elsewhere, global scale of exposure, and changes in cryptocurrency technologies. The District's experience in serving cryptocurrency loads over

the past six years has reinforced this conclusion. In 2018, after considerable process, the District rolled out new rates and policies to address the issues, only to be forced to revisit the issues because of a dramatic change in cryptocurrency prices and load inquiries that would double the District's current local load. Currently, the District is again reviewing the cryptocurrency and data processing rates as the District has learned those two load types are similar in nature from an operations perspective, substantial load growth has not occurred, and risk appears to be manageable at current load levels being less than 10 MWs prompting the introduction of a threshold to serve this class at a cost of production rate before blending with market-based rates once the threshold is exceeded. Data center risk assessment does not lend itself to precise calculation because almost every significant variable one would use for a risk calculation has a big question mark around it. Therefore, significant judgment was needed in this risk assessment.

After exploring several possible methods for quantifying the many risks associated with serving data centers, staff is proposing decreasing the risk adder of 1.3¢/kWh to .527¢/kWh as an appropriate risk premium, given all the risk factors, that is commensurate with the inclusion of a threshold for a cost-based energy rate and the market-based costs and risks associated with MWs above the threshold. Rather than trying to directly quantify all of the potential risks, the District used the following metrics as proxies to benchmark and validate the recommended threshold and risk premium with the intent to keep the District's existing customer owners neutral, while allowing for some growth at cost of production rates. The following describes those considerations and more specifically risk calculations where applicable.

- **Generation Portfolio – Balanced Risk Approach** – The District relies on the generation surplus in the wholesale market to support its current and existing rate structure and local load requirements across rate classes. By design, the District has implemented a systematic hedge program for the generation portfolio to provide revenue certainty, reduce revenue volatility, and mitigate risks with streamflow conditions and operations that impacts the number of megawatts the hydro plants can generate to serve the District's customers and fulfill other contractual obligations, as part of a wholistic approach to managing the District's generation portfolio. To ensure customer owners have access to low rates and reliable power, the District has implemented a long-term marketing strategy leveraging diversified contracts that recover costs through long-term cost-plus slice contracts, monetizes the capacity and carbon-free value, mitigates price, streamflow and operational risks through market-based slices, and reserves carbon-free generation to serve District load. This approach effectively protects the downside risk of the wholesale market and escalating costs for the District and helps to accomplish its objective to protect current rates and avoid significant rate increases for traditional long-standing ratepayers in Chelan County.

  The District recognizes that the full market-based approach for the energy rate created significant volatility, and most recently, high prices in the wholesale market have caused the rate to vary significantly from year to year. Customers in the affected rate class have expressed concerns about the unpredictable nature of the rate for planning purposes and the sustainability of their respective business models in the long-term. Additionally, the District recognizes that the financial and operational impacts and incremental risks to the District with limited growth in this rate class have been manageable based on the last 5 years of experience since the rate was established. Thus, staff is recommending a blended approach for the energy rate that allows the customer to participate in cost of production energy rates up to a threshold of 10 MWs before converting to a market-based rate plus other energy related charges, including a risk premium for MWs above the threshold that will cover incremental costs the District incurs from

purchased power and incremental risks that are inherent as the load grows in this rate class. This balanced approach is beneficial to the customer in having more predictable rates, while protecting the generation portfolio and long-term marketing strategy that is designed to mitigate price, streamflow, operational, and cost risks to protect the sustainability of the District's financial and service models.

Staff contemplated the appropriate threshold that would represent the right balance for this rate class and the District with consideration of keeping the District's customer owners neutral. The current approved load for the cryptocurrency/data processing for loads is approximately 9 MWs in total with minimal applications in the queue seeking incremental power. Since the District's experience with this load type thus far has been manageable from a financial, operational and risk perspective, Staff recommended allowing some room for incremental growth up to 10 MWs before the energy rate would proportionately transition to market-based serving from purchased power. The recommended threshold represents approximately 5% of the District's local retail load, thus limiting concentration from the generation portfolio that could otherwise impede the District's ability to keep customer owner's neutral at cost of production rates. Additional factors included minimizing the impact of the long-term marketing strategy that includes targeted 20-30% of generation allocated to local retail load. The targeted cap at 30% allows for incremental organic load growth within the County and for expected future Schedule 4 large loads locating in Chelan County, while retaining the 70-80% for diversified contracts that help support low rates and mitigate key risks for the District as cited above.

Given the decision to protect the District's ratepayers from incremental generation portfolio risk by not altering the District's current hedging program, the District is pursuing a blended cost of production and market-based energy rate component. However, the market purchases and continued risk of load growth and concentration still exists. The District must mitigate or protect against the risks through the risk adder, including:

- **Market-Price Risk -** Based on the assumption that the District anticipates purchasing a fixed price block of energy equivalent to the delta between the forecasted load for data centers and the established 10-MW threshold that the District is allocating as a cost of production energy rate, the District takes on price risk for that forward market purchase. The risk is that if the load intended to be served from this purchase goes away (transient, crypto price decline, as examples), the District will be long fixed price energy positions that will need to be sold in the market. If the market drops and the position is sold in the market, the District realizes a net loss. Leveraging the Net Wholesale Revenue Simulation Model, six (6) annual simulations were used, each with a model run date that represents roughly 4 months prior to the forward price curve start date for the prompt year to resemble the amount of time between the rate set date (Feb. 1) and the rate effective date (June 1) for the fixed price purchase. The 6-year average of the delta between the 50th and 10th percentiles is $12.47. In other words, if the risk described materialized and the market dropped to the 10th percentile, the District is taking on $12.47 of price risk for that market purchase based on these assumptions. It was also determined that the delta between the 10th percentile and the 50th percentile is consistently ~32% of the 50th percentile. Given that the District's Schedule 36 methodology is to calculate the energy price on February 1 for each calendar year for the prompt year, it is reasonable to conclude that the delta

will continue to be ~32% for future price scenarios. Thus it is the basis for developing the market-price risk component for future market purchases. To develop the risk component, 32% was applied to the Mid-C Forward Price Curve as of 2/1/2023 for six (6) future 12-month annual periods starting with June 2023 through May 2024 to identify the future expected price delta between the 50th and 10th percentiles. The expected delta was then multiplied by a 10% likelihood factor for the price drop and averaged for the 6 years to calculate the market-price risk component at $2.47/MWh or 0.247¢/kWh. Staff recommends fixing the market-price risk component rather than recomputing each year based on updated prices. The 10th percentile is consistent with the District's Power Risk Management policy in its approach to Minimum Revenue Requirements and used to calculate the District's "unusual" scenario as defined by resolution in the District's Financial Policy Metrics. It is recognized that there are other risks and other costs associated with market purchases not considered here. Market prices are volatile and can change substantially, which may prompt the District to revisit the market-price risk component.

- **Credit Rating Downgrade Risk** – A credit rating downgrade is a material event for the District and would signal to the external stakeholders, such as existing and future bondholders, that the financial strength and/or risk profile of the District has changed or perceived to be different based on changed conditions. This would immediately impact the District's bottom line income potential with respect to an existing contract that supports the debt portfolio, a long-term contract that provides revenue from the credit spread, and would impact the District's ability to issue cost-effective debt in the future, which are costs that would be borne by all of the District's ratepayers. This risk is warranted given the continued uncertainty of this relatively new rate class and associated risks of future load concentration of a potentially transient rate class. Given that Staff has incorporated new mitigations, such as adding substation limits and increased security deposits, a 10% scaler is applied. Staff estimates the costs of a one tier credit downgrade at 0.010¢/kWh.

- **Liquidity Risk** – Providing reliable electricity to the District's customer owners is a key part of the District's Mission Statement and continuing to improve that reliability metric is one of the District's strategic priorities. Additional costs may arise when market supply is limited or not readily available or energy is curtailed or is not cost-effective due to liquidity challenges. Staff estimates this cost at 0.27¢/kWh, which is the difference between forward on-peak and off-peak wholesale prices applied to peak hourly load divided by monthly average energy usage and applying a 10% scalar.

The three above risks total .527¢/kWh. The risk premium is designed to protect the District from adverse financial consequences related to market purchases and a credit downgrade event when the load exceeds a designated threshold. The District's approach to the risk premium was revisited during this effort and it was recognized that the risks identified in the initial cryptocurrency rate have not been materially realized as substantial load growth in this rate class has not occurred, up to this point, although remains a possible outcome. At the current threshold of 10 MWs, the risks appear to be manageable for the District and will be mitigated through additional provisions in the rate class that are supportive of customer owner neutrality. It is recognized that the District will have added costs that will need to be recovered and incremental risks that the District will take on as a potentially transient rate class grows beyond the threshold served from market power, thus the need for other energy charges including a risk premium to protect against adverse consequences to keep the District's existing

customer-owners and ratepayers neutral and preserve current low rates that benefit the county. The threshold, other energy charges with the risk premium will be monitored and may change as the industry and District experience evolves over time. The District will consider new and evolving circumstances associated with risk, the data center industry and local experience with this rate class, rate class growth, regulations, generation portfolio mix and hedging strategies, and feedback from rating agencies during periodic reviews.

RESOLUTION NO. _____

A RESOLUTION AUTHORIZING AMENDMENT NO. 6 TO SERVICES AGREEMENT (SA NO. 20-11086) WITH ENGLOBE CORP TO PROVIDE THIRD PARTY INSPECTION SERVICES

FACTUAL BACKGROUND AND REASONS FOR ACTION

The District entered into a Services Agreement (SA No. 20-11086) on January 25, 2021, with Englobe Corp to provide third party inspection services, in an amount not to exceed $450,000. Amendments 1-5 did not revise the not to exceed amount.

District staff has identified the need for additional third party inspection services for the Rock Island Turbine and Generator Rehabilitation project, and other projects ongoing at the District. Resolution No. 17-14215 requires that the Commission, by resolution, authorize Amendments to Service Agreements when the Amendment increases the total contract price to over $500,000.

District staff recommends that it is in the best interest of the District to increase the not to exceed amount of Services Agreement No. 20-11086 with Englobe Corp in the amount of $675,000, for a total revised contract price not to exceed $1,125,000.

The General Manager has reviewed District staff's recommendation and concurs in the same.

ACTION

IT IS RESOLVED BY THE COMMISSION OF PUBLIC UTILITY DISTRICT NO. 1 OF CHELAN COUNTY, WASHINGTON as follows:

Section 1. The General Manager is hereby authorized to execute an Amendment to Services Agreement (SA No. 20-11086) with Englobe Corp to provide the additional services identified above. The revised contract price will not exceed $1,125,000 without prior Commission approval. A copy of the Amendment is on file in the offices of the District.

DATED this 21st day of August 2023.

_____
President

ATTEST:

_____ _____
Vice President Secretary

_____ _____
Commissioner Commissioner

Seal

RESOLUTION NO. _____

A RESOLUTION APPROVING BUDGET REVISION, BID ADVERTISEMENT, AWARD AND CONTRACT SIGNATURE FOR LAKE CHELAN POWER TUNNEL ISOLATION SYSTEM (BID NO. 22-12725)

FACTUAL BACKGROUND AND REASONS FOR ACTION

The District is proposing to replace the stop logs with a drop gate assembly. To ensure a prompt emergency response the drop gate will be configured for remote operation from the Lake Chelan powerhouse or Rocky Reach Dam. The assembly will consist of a 16 ft x 16 ft, 30-ton steel gate with an electric hoist and supporting structure. Appurtenant work components will include modifications to the gate slot, air vent pipes, refill valves, a liquid propane backup generator, and site grading. Underwater and over-water work will be required.

Resolution No. 17-14215 requires Commission approval of bids and Authorization to invite bids that are estimated to exceed $3,000,000. Bidding documents for Bid No. 22-12725, including specifications are being prepared by the District and will be on file in the offices of the District.

Resolution No. 17-14215 requires Commission approval to award bids estimated to exceed $3,000,000. Bid No. 22-12725 has an engineer's estimate that exceeds $3,000,000. Should all Bids exceed the engineer's estimate by more than 15%, excluding sales tax, an award will not be issued pursuant to RCW 54.04.080.

District staff recommends that Bid No. 22-12725 is in the best interest of the District and that said documents be approved and invitation for bid be published.

District staff also recommends it is in the District's best interest to authorize staff to Award Bid No. 22-12725 in an amount not to exceed 15% above the engineer's estimate, excluding sales tax, and to authorize the General Manager or his designee to enter into contract with the lowest responsive and responsible bidder with a legally compliant bid that meets the District's terms and conditions.

District staff also recommends increasing the total project budget from $3,850,000 to $6,000,000. This increase addresses construction cost escalation and additional design fees.

The General Manager of the District has reviewed District staff's recommendation and concurs in the same.

ACTION

IT IS RESOLVED BY THE COMMISSION OF PUBLIC UTILITY DISTRICT NO. 1 OF CHELAN COUNTY, as follows:

Section 1. The bidding documents (Bid No. 22-12725) for the Lake Chelan Power Tunnel Isolation System are hereby approved and the General Manager of the District is hereby authorized to invite sealed proposals for furnishing said labor and materials.

Section 2. The Commission hereby authorizes staff to award Bid No. 22-12725 for the Lake Chelan Power Tunnel Isolation System to the lowest responsive and responsible bidder in an amount not greater than 15% above the engineer's estimate, excluding sales tax. Furthermore, the General Manager of the District is hereby authorized to enter into contract with the lowest responsive and responsible bidder with a legally compliant bid that meets the District's terms and conditions. A copy of the contract(s) will be on file in the offices of the District.

Section 3. The total project budget for capital project LC210001, LC Seismic Study-Auto Closure Gate, is hereby revised to $6,000,000.00 to cover the remaining planned work.

DATED this 21st day of August 2023.

_____
President

ATTEST:

_____ _____
Vice President Secretary

_____ _____
Commissioner Commissioner

Seal