ORDINANCE NO. 2026-15

CITY OF CLYDE, OHIO

REPEALING AND REPLACING THE CITY'S INDUSTRIAL POWER RATE SCHEDULE "IP"

WHEREAS, the City previously established an Industrial Power Rate Schedule – Schedule "IP" (Schedule "IP") on November 15, 1988, pursuant to Ordinance 1988-84; and

WHEREAS, the method of charges for certain power supply related services have significantly changed since 1988; and

WHEREAS, the City's utility rate consultant, Courtney & Associates, has recommended that the City revise Schedule "IP" to reflect these changes.

NOW, THEREFORE, BE IT ORDAINED by the Council of the City of Clyde, State of Ohio:

SECTION 1. Effective with all bills rendered after the effective date of this ordinance, the existing Schedule"IP" is hereby repealed and replaced by the Schedule "IP" attached hereto as Exhibit "A" and made a part of this ordinance.

SECTION 2. This ordinance shall be in full force and effect at the earliest date provided by law.

Adopted: 2-3-2026

Authorized: Dan McCauley

Attest: Janet R. Dickman

Approved to form:

Exhibit "A"

City of Clyde, Ohio

INDUSTRIAL POWER RATE SCHEDULE
SCHEDULE "IP"

AVAILABILTY: Rates under this Schedule IP are available to all electric power customers of the City of Clyde, Ohio, Electric Utility Division ("Utility") which are located adjacent to existing 69 kV transmission facilities of the Utility that (1) take service at 69 kV; and (2) guarantee a Contract Billing Capacity specified by contract, but not less than 5,000 kW.

Service under this Schedule will be furnished only on a year-round basis by contract in accordance with the following stipulations and also in accordance with the Utility's General Rules and Regulations or subsequent revisions thereof (provided that any subsequent revisions do not materially affect customer's obligation hereunder and are not inconsistent with the terms of the contract) which are a part of this rate schedule as if fully written herein.

GENERAL RATE CONCEPT: The intent of this Schedule IP is to allocate to each customer receiving service under this Schedule only those costs which are reasonably attributable to providing service to that customer at 69 kV. Costs which are not reasonably attributable to providing such service at 69 kV shall not be recovered under this rate schedule.

COST RECOVERY: Costs which the Utility has determined are reasonably attributed to providing service to customers served at 69 kV are those costs related to Power Supply, Transmission and Capacity, Debt Service/Coverage/Renewals and Improvements, Operation and Maintenance, and Metering and Billing Expenses. Defined below are the various items which make up these cost components related to providing service at 69 kV.

POWER SUPPLY: The Utility shall recover that portion of power supply related costs which are attributed to providing service to each customer receiving service under this schedule. Such cost shall include Demand, Reactive Demand, and Energy related charges billed to the Utility by its power suppliers.

All Power Supply Energy related charges will be allocated to each customer receiving service under this schedule on a prorata based on the ratio of the customer's Monthly Billing kWh to the sum of (a) the Monthly Billing kWh for all IP customers plus (b) the Utility Distribution System's Monthly Billing kWh.

Power Supply Demand related charges will be allocated to each customer receiving service under this schedule on a prorata based on the ratio of the customer's Monthly Power Billing Demand to the sum of (a) the Monthly Power Billing Demand for all IP customers plus (b) the Utility Distribution System's Monthly Power Supply Demand

Power Supply Reactive Demand related charges will be allocated to each customer receiving service under this schedule on a prorata based on the ratio of the customer's Monthly Reactive Billing Demand to the sum of (a) the Monthly Reactive Billing Demand for all IP customers plus (b) the Utility Distribution System's Monthly Reactive Billing Demand.

TRANSMISSION AND CAPACITY: The Utility shall recover that portion of transmission and capacity related costs attributable to receiving power and energy delivered to Utility's 69 kV System. Such costs currently include AEP Transmission Demand, PJM RPM Capacity and Transmission Ancillary Service Charges billed to the Utility by its power suppliers.
Transmission Ancillary Service related charges will be allocated to each customer receiving service under this schedule on a prorata basis by comparing the customer's Monthly Billing kWh to the sum of (a) the Monthly Billing kWh for all IP customers plus (b) the Utility Distribution System's Monthly Billing kWh.

AEP Transmission Demand related charges will be allocated to each customer receiving service under this schedule on a prorata basis by comparing the customer's Transmission Peak Load Contribution to the sum of (a) the Transmission Peak Load Contributions for all IP customers plus (b) the Utility Distribution System's Transmission Peak Load Contribution.

PJM RPM Capacity related charges will be allocated to each customer receiving service under this schedule on a prorata based on the ratio of the customer's PJM Capacity Peak Load Contribution to the sum of (a) the PJM Capacity Peak Load Contributions for all IP customers plus (b) the Utility Distribution System's PJM Capacity Peak Load Contribution.

DEBT SERVICE/COVERAGE/RENEWALS AND IMPROVEMENTS: The Utility shall recover an allocable share of the debt service, coverage and renewals and improvements expenses attributed, pursuant to the formula set forth below, to providing service to customers receiving service under this schedule. These costs shall include such items as the costs of interconnecting the utility to AEP's 69 kV transmission System, (or other transmission service providers), the cost associated with constructing the Utility's 69 kV transmission system (including control devices, 69 kV circuit breakers and rights-of-way), the cost incurred by the Utility associated with interconnecting the Utility's 69 kV transmission facilities to customers receiving service under this schedule, the cost associated with the purchase of major equipment needed to maintain the Utility's 69 kV transmission system, the cost associated with maintaining an inventory of spare parts (poles, insulators, etc.) needed for the Utility's 69 kV transmission system, the costs incurred by the Utility associated with the establishment of the Utility (excluding those costs directly attributed to the Utility Distribution System) and other costs related to financing the above stated costs including allowances for debt service reserves, operating reserves and renewal and improvement reserves. In

addition, the Utility shall recover from the customers served under this schedule an allowance for debt service coverage as required of the Utility for rendering service to customers under this rate schedule.

The above costs shall be allocated to each customer served under this schedule on the basis of the customer's proportionate utilization of the Utility's 69 kV transmission facilities. Each month during the subsequent calendar year the customer shall pay to the Utility an amount equal to the product of the Utility's anticipated monthly debt service, coverage and renewals and improvement requirements multiplied by the ratio of the customer's Transmission Billing Capacity to the sum of the Transmission Billing Capacity for all IP customers plus the Utility Distribution System's Transmission Billing Capacity.

Within three (3) months of the end of each calendar year, the Utility shall compare its actual debt service, coverage, and renewals and improvement requirements to the anticipated amounts and shall reconcile any differences by refunding to or collecting from customers receiving service under this schedule such differences on the basis of the customer's average annual prorata share of the debt service, coverage, and renewals and improvement requirements.

OPERATION AND MAINTENANCE: The Utility shall recover those expenses attributed to the operation and maintenance of the 69 kV transmission facilities, including an allocable portion of the Utility's administrative and general expenses (including insurance associated with transmission service and facilities) and maintenance of the transmission facilities and rights-of-way. During each month of the subsequent year, customers receiving service under this schedule shall pay to the Utility an amount equal to the product of the Utility's anticipated monthly operation and maintenance expenses multiplied by the ratio of the customer's Transmission Billing Capacity to the sum of the Transmission Billing Capacity for all IP customers plus the Utility Distribution System's Transmission Capacity Requirements.

Within three (3) months of the end of each calendar year, the Utility shall compare its actual operation and maintenance expenses to the budgeted amounts and shall reconcile any differences by refunding to or collecting from customers receiving service under this schedule such differences on the basis of the customer's average annual prorata share of the Operation and Maintenance costs.

METERING AND BILLING: The Utility shall recover those costs associated with installing, maintaining and reading the meters installed for customers served under this schedule. The Utility shall also recover its costs associated with the billing and collection of customers served under this rate schedule. These costs are currently estimated at $1,000 per month, but shall be reviewed annually by the Utility and adjusted as appropriate.

METERING/LOSS ADJUSTMENTS: Service under this schedule will normally be metered at 69 kV; however, the Utility reserves the right to meter the service at the secondary voltage of the customer's substation(s) and compensate the meter readings to 69 kV. Said compensation will be based upon the computed losses associated with the customer's facilities between the point of delivery and the metering point.

In the event of the stoppage or failure of any meter to register the amount of energy consumed or demand taken, customer will be billed for such period on an estimated demand and consumption based upon the use by customer of demand and energy in a similar period of like use. The metered kW and kVar demands shall be registered by 60-minute integrating demand meters.

MONTHLY BILLING KWH: The customer's Monthly Billing kWh will be equal to the customer's metered kWh (adjusted for losses to 69 kV, if needed).

MONTHLY POWER BILLING DEMAND: The customer's Monthly Power Billing Demand will be determined as the greater of (1) the customer's contribution to the Utility's system peak demand for the month based on coincident actual metered kW demand, or (2) sixty percent (60%) of the customer's maximum Monthly Power Billing Demand experienced during the prior eleven (11) months, or (3) sixty percent (60%)of the customer's Contract Capacity as specified by contract. For customers installing onsite generation, the customer's Monthly Power Billing Demand shall not be less than the customer's highest Monthly Power Billing Demand occurring during the twelve-month period immediately prior to the installation of the onsite generation.

MONTHLY REACTIVE BILLING DEMAND: The customer's Monthly Reactive Billing Demand will be determined as the customer's maximum metered kVar demand for the month (adjusted for losses to 69 kV, if needed).

TRANSMISSION PEAK LOAD CONTRIBUTION: The customer's Transmission Peak Load Contribution will be determined as the customer's demand (in kW) occurring during the applicable AEP East Zonal Network Service Peak Load. The customer's Transmission Peak Load Contribution shall not be less than zero.

PJM CAPACITY PEAK LOAD CONTRIBUTION: The customer's PJM Capacity Peak Load Contribution shall be adjusted every June and will be determined as the customer's average demand (in kW) occurring during PJM's five highest demand hours for the prior summer months (June through September). The customer's PJM Capacity Peak Load Contribution shall not be less than zero.

UTILITY DISTRIBUTION SYSTEM'S TRANSMISSION PEAK LOAD CONTRIBUTION: The Utility Distribution System's Transmission Peak Load Contribution will be determined as the Utility Distribution System's demand (in kW) occurring during the applicable AEP East Zonal Network Service Peak Load.

UTILITY DISTRIBUTION SYSYEM'S PJM CAPACITY PEAK LOAD CONTRIBUTION: The Utility Distribution System's PJM Capacity Peak Load Contribution will be determined as the Utility Distribution System's average demand (in kW) occurring during PJM's five highest demand hours for the prior summer months (June through September).

TRANSMISSION BILLING CAPACITY: The customer's Transmission Billing Capacity will be determined as the non-coincident maximum metered kW demand experienced by the customer since the last date that service commenced to a new customer under this schedule.

UTILITY DISTRIBUTION SYSTEM: The electric load that receives service through facilities operated at less than 69 kV.

UTILITY'S MONTHLY BILLING KWH: The Utility's Monthly Billing kWh will be the sum of the Utility Distribution System's metered kWh (adjusted for losses to 69 kV), including energy supplied by Non-Retail Behind-the-Meter Generation, such as the existing Clyde Solar Project, but excluding the existing OnSite Partners Peaking Generators.

UTILITY DISTRIBUTION SYSTEM'S MONTHLY POWER BILLING DEMAND: The Utility Distribution System's Monthly Power Billing Demand will be determined as the greater of (1) the Utility Distribution System's contribution to the Utility's system peak demand for the month based on coincident actual metered kW demand, or (2) sixty percent (60%) of the maximum Utility Distribution System's Monthly Capacity Requirements experienced during the prior eleven (11) months.

UTILITY DISTRIBUTION SYSTEM'S MONTHLY REACTIVE BILLING DEMAND: The Utility's Distribution System's Monthly Reactive Billing Demand will be determined as the Utility Distribution System's maximum metered kVar demand for the month.

UTILTY DISTRIBUTION SYSTEM'S TRANSMISSION BILLING CAPACITY: The Utility Distribution System's Transmission Capacity Requirements will be determined as the non-coincident maximum metered kW demand experienced by the Utility Distribution System since the last date that service commenced to a new customer under this schedule.

TERMS OF PAYMENT: Bills are payable within 7 days of receipt of bill. On all accounts not so paid, interest on unpaid amount will accrue at the rate of 6% annum from the date due until the date payment is made. All bills are payable at the business offices or collection agencies or Utility within the time limit specified above. The word "month" as used herein is hereby defined to be the elapsed time between two successive meter readings approximately thirty days apart.

Adopted by Clyde City Council on _____, 2026
EFFECTIVE: For All Bills Rendered on or After _____, 2026