PSC REF#:616740

SERVICE DATE
Oct 29, 2026

Public Service Commission of Wisconsin
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PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of City of Kaukauna, Outagamie and Calumet Counties, Wisconsin, as an Electric Public Utility, for Authority to Adjust Electric Rates	2800-ER-110

FINAL DECISION

This is the Final Decision in the Class 1 proceeding conducted by the Public Service Commission (Commission) on the application of the City of Kaukauna (applicant), as an electric public utility, for authority to adjust electric rates. The application is APPROVED as conditioned by this Final Decision.

Procedural Background

On January 29, 2025, the applicant submitted an application to the Commission for authority to increase electric rates by $2,277,942, or 4.07 percent. The applicant's last rate change was approved in docket 2800-ER-109 by Final Decision dated December 31, 2023. The applicant cited increased operation and maintenance expenses as the contributing factor for the rate increase request. The final overall rate change authorized is $1,547,660, or 2.77 percent for the test year which ends December 31, 2025.

On January 12, 2026, pursuant to due notice, the Commission held a telephonic hearing at Madison and Kaukauna. The applicant, Citizens Utility Board of Wisconsin (CUB), and Wisconsin Industrial Energy Group (WIEG) were parties to the proceeding. The appearances in this proceeding are listed in Appendix A.

On April 9, 2026, the Commission discussed the record in this proceeding at its open meeting. (PSC REF#: 590570.)

Findings of Fact

1. The applicant is a member-owner of WPPI Energy (WPPI) and, as such, purchases some of its electric capacity and energy requirements from WPPI.

2. A reasonable estimate of average net investment rate base for the test year is $95,727,001.

3. The applicant's present authorized rates for electric utility service will produce total operating revenues of $58,525,424, which are less than the applicant's revenue requirement of $60,073,083 for the test year. The applicant's present rates are unreasonable and unjust as they are insufficient to cover the application's test year operating expense and to provide an opportunity for a reasonable return on utility investments.

4. The rate of return on average net investment rate base at current rates of 4.78 percent is unreasonable and inadequate.

5. It is reasonable for the applicant to amortize the $1,445,668 of deferred revenue from the sale of capacity from the applicant's Elm Street Combustion Turbine (CT) over 5 years into Account 447.

6. It is reasonable for the applicant not to apply carrying costs to the refund of revenues collected from the sale of capacity from the applicant's Elm Street CT.

7. It is reasonable to accept Commission staff's uncontested audit adjustments.

8. A reasonable utility ratemaking capital structure for the test year consists of 57.14 percent municipal equity and 42.86 percent long-term debt.

9. A reasonable return on municipal equity is 8.61 percent.

10. The applicant's composite cost of debt is 3.45 percent. A reasonable return on average net investment rate base that will provide adequate interest coverage is 6.40 percent.

11. Authorizing the applicant to continue to apply a power cost adjustment clause (PCAC) for retail electric service during the test year is reasonable.

12. An increase in the applicant's operating revenues for the test year of $1,547,660 is necessary to generate a 6.40 percent return on average net investment rate base and to cover the applicant's total cost of service.

13. It is reasonable to require the applicant to make an adjustment to Account 216.2 for the year 2024 such that Account 101.2 utility plant in service contributed plant less Account 111.2 accumulated depreciation of utility plant in service contributed plant matches Account 216.2 surplus contributions.

14. It is reasonable to require the applicant to correct the Account 302 accumulated depreciation balance in the applicant's 2024 Annual Report to reflect a 2024 first of year accumulated depreciation balance of $26,729 in Account 302, consistent with the adjustments and findings made in this proceeding.

15. It is reasonable for the Commission to consider a range of cost-of-service study (COSS) when determining final revenue allocation and rate design.

16. It is reasonable to use the rate design and revenue allocation proposed by Commission staff, adjusted for the final revenue requirement and specific issues as set by the Commission.

17. It is reasonable to adopt a non-sufficient fund (NSF) rate of $17 to be charged in the OC-1 tariff.

18. It is reasonable to simplify the Commitment to Community (CTC) Rider as proposed by Commission staff, including updating the CTC Rider to include Street and Security Lighting Service (MS-1).

19. It is reasonable to update the base demand cost factors (BDCF) rates in the tariff to three decimal places.

20. It is reasonable to update the wording on the Cp-6 rider to "30 On-Peak Period days".

21. The rates and rules in Appendices D and F are just and reasonable and will permit the applicant to earn the necessary revenue requirement for the test year.

22. The annual depreciation rates in Appendix G are reasonable.

23. Energy conservation, renewable resources, or energy priorities listed in Wis. Stat. §§ 1.12 or 196.025 and their combination would not be a cost effective, technically feasible, or environmentally sound alternative to the rate increase authorized in this Final Decision.

Conclusion of Law

1. The applicant is a municipal electric public utility as defined in Wis. Stat. §§ 66.0801 and 196.01(5).

2. The Commission has authority under Wis. Stat. §§ 196.025, 196.03, 196.20, and 196.37, to authorize the applicant to establish electric rates and rules and annual depreciation rates in accordance with this Final Decision and to determine that the rates and rules in Appendices D, F, and G are reasonable and just as a matter of law.

Opinion

Net Investment Rate Base

The average net investment rate base for the test year is as follows:

Electric Utility Plant		$174,142,977
Less:	Accumulated Depreciation	81,144,667
Net Plant:		$92,998,310
Plus:	Materials and Supplies	2,728,691
Less:	Customer Advances	0
Less:	Reg. Liability (Contrib. Accum. Depr.)[1]	0
Net Investment Rate Base		$95,727,001

This rate base is reasonable and just.

Elm Street Capacity Sales Revenues

The applicant owns the Elm Street CT natural gas-fired generating unit. In 2016, the applicant signed a contract to sell capacity from the Elm Street CT to WPPI from January 1, 2017 through June 1, 2026.[2] As part of this contract, the applicant received a one-time upfront payment in 2016 of $1,445,668, which was deferred over the life of the contract and was recorded under Account 447 (sales for resale) in the applicant's PSC Annual Report filings based on an amortization schedule defined in the contract.

Commission staff identified that the exclusion of this revenue from the revenue requirement in previous rate proceedings resulted in a potential over-collection of revenue from the applicant's retail customers. Commission staff proposed returning the $1,445,668 of

[1] Authorized in docket 05-US-105, Investigation of the Accounting Treatment for Account 271, Contributions in Aid of Construction and Modification of the Uniform Systems of Accounts for Municipal Electric, Gas, Water and Sewer Utilities. Supplemental Decision dated September 9, 2004.
[2] Ex.-KU-Wallin-1

deferred revenue, without carrying costs, to the applicant's customers through an annual amortization of $289,134 applied to Account 447 over a 5-year period. The applicant and WIEG did not dispute the amount of deferred revenue to be returned to customers.

Commission staff's proposed revenue requirement was based on a 5-year amortization period for the deferred Elm Street CT revenue. Commission staff also provided additional amortization period alternatives for the Commissions consideration.[3] The applicant proposed a 9-year amortization schedule to match the contract length associated with the deferred revenue, noting that it was consistent with the 10-year amortization related to the Appleton Coated receivership authorized in docket 2800-ER-108. CUB stated it favored either the 4- or 5-year amortization period alternatives and asserted that the longer 9-year amortization period proposed by the applicant would exacerbate intergenerational inequity by further delaying the benefits to customers from the 2016 Elm Street CT capacity sale.

Commission staff's proposed revenue requirement did not include carrying costs consistent with previous amortizations. In docket 2800-ER-109, the Commission considered carrying costs associated with unauthorized revenue collected through a Wholesale Delivery Sales Agreement (WDSA). In that proceeding, the Commission found it reasonable to not include carrying costs, as the collection and omitted reporting of the WDSA revenue appeared to be unintentional. Commission staff also provided carrying cost options for Commission consideration, including carrying costs at the customer deposit rate or carrying costs at the applicant's authorized rate of return. The applicant supported Commission staff's proposal to exclude carrying costs. The applicant stated that since the applicant is a municipal-owned utility, no shareholders benefited from the effective borrowing of over-collected revenue from

[3] Ex.-PSC-Field-1: Schedule 3.

customers, and that the financial impact of carrying costs paid by the utility would simply fall back on customers. CUB did not object to excluding carrying costs on the condition that the amortization period be 5 years or less but recommended carrying costs at the applicant's authorized rate of return if the proposed 9-year amortization period were to be applied due to both the length of the amortization and delay in returning the revenue to customers.

The Commission finds it reasonable to require the applicant to return the $1,445,668 in deferred revenue associated with the 2016 Elm Street CT capacity sale to customers. The Commission finds it important to return the revenue to customers promptly and, therefore, that it is reasonable to apply for a 5-year amortization period, without carrying costs. With a 5-year amortization period, the Commission finds that it is not necessary nor reasonable to apply carrying costs.

Comparative Income Statement

Income statements showing revenues and expenditures estimated for the test year ending December 31, 2025, at present rates and at rates authorized in this Final Decision, are contained in Appendix B. Such income statements are reasonable and just for purposes of this proceeding. Appendix B also shows the percentage change in revenues for the various rate classes at present and authorized rates. The applicant's present rates are unreasonable and unjust because they produce inadequate revenues.

The depreciation expense included in the revenue requirement for the test year was computed using the depreciation rates shown in Appendix G. These depreciation rates are effective on the effective date of this Final Decision for computing the depreciation expense on the average investment for each plant account.

Contributed Plant

During this proceeding, variances were found in the applicant's net contributed plant balance (Account 101.2 contributed plant in service minus Account 111.2 contributed plant accumulated depreciation) based on Schedule F-08 of the Annual Report, and the Account 216.2 surplus contributions balance as shown on Schedule F-02 of the Annual Report. It is reasonable to require the applicant to make an adjustment to Account 216.2 for the year 2024 such that Account 101.2 utility plant in service contributed plant less Account 111.2 accumulated depreciation of utility plant in service contributed plant matches Account 216.2 surplus contributions.

Account 302

Prior to 2021, the applicant had no balance under Account 302 (franchises and consents). In 2021 and 2025, additions were made to this account for the renewal of Federal Energy Regulatory Commission (FERC) licenses for the applicant to operate its hydroelectric facilities. In the applicant's previous rate proceeding in docket 2800-ER-109, the Final Decision did not specify a depreciation rate for Account 302, and the applicant had not been booking depreciation or accumulated depreciation in this account.

The Commission finds it reasonable to establish a depreciation rate of 2.0 percent for Account 302 as identified in Appendix G in this proceeding based on a term of up to 50 years for the FERC licenses included in Account 302. Commission staff calculated that the Account 302 accumulated depreciation balance should have been $26,729 at the beginning of 2024 based on the amount of the 2021 addition and the filed 2.0 percent depreciation rate. Therefore, the Commission finds it reasonable to require the applicant to correct the Account 302 accumulated

depreciation balance in the applicant's 2024 Annual Report to reflect a 2024 first of year accumulated depreciation balance of $26,729 in Account 302, consistent with the adjustments and findings made in this proceeding.

Return on Rate Base

It is reasonable to expect the applicant to pay $35,090,268 to its wholesale supplier, WPPI, for purchased power during the test year. During this period, the Commission expects the applicant to sell 558,691,089 kilowatt-hours (kWh) of energy. The Commission expects the applicant's present rates to produce total operating revenues of $58,525,424 against total operating expenses of $53,946,623, yielding a net operating income of $4,578,801. This net operating income provides a 4.78 percent rate of return on the above determined average net investment rate base of $95,727,001. Because the present rates produce a low rate of return, they are inadequate.

It is reasonable to estimate the applicant's capital employed in providing public utility service as 57.14 percent municipal equity and 42.86 percent long-term debt. The composite cost of debt capital is 3.45 percent. A return on rate base of 6.40 percent, as proposed by Commission staff consistent with past Commission staff practice in similar cases, will provide a return on municipal equity of 8.61 percent and 2.76 times interest coverage. While the applicant initially requested a return on rate base of 6.50 percent, the applicant and parties did not oppose Commission staff's suggestion of 6.40 percent. Therefore, the Commission finds a rate of return of 6.40 percent applied to net investment rate base in determining revenue requirement for the purposes of this proceeding is just and reasonable.

Power Cost Adjustment Clause

The applicant's earnings are extremely sensitive to the wholesale rates and fuel adjustment charged by its supplier and to the cost of fuel of generation. Purchased power and fuel costs represent approximately 65.0 percent of the applicant's total operating expenses. Fluctuations in the applicant's earnings can result from changes in the wholesale demand-energy rate and fuel adjustment charged by WPPI and changes in the cost of fuel. In order to mitigate fluctuations in the applicant's earnings due to changes in the cost of purchased power and fuel, the Commission authorizes the applicant to continue to apply a PCAC to all of its retail bills. This clause permits increases or decreases in the cost of purchased power and fuel to be passed on directly to the customer. The applicant presumably makes no profit from applying this PCAC to its retail bills.

This Final Decision revises the PCAC to reflect the change in the base average cost of power (the "U" factor of the clause) for the test year. The PCAC is applicable each month and shall reflect the difference between monthly and test period wholesale purchased power costs and the applicant's fuel costs.

The authorized rates, as shown in Appendix D, reflect the test year PCAC factor. This average per kilowatt-hour adjustment to a customer's retail electric bill represents expected changes in the wholesale cost of purchased power and fuel for the test year. The cost of purchased power used to compute this average adjustment is based upon rates set by WPPI which are effective on and after January 1 of the test year.

Rates

The Commission adjusted the applicant's base rates in addition to revising the PCAC. The authorized rates will increase revenues by approximately $1,547,660 annually, or 2.77 percent, resulting in an estimated net operating income of $6,126,461 for the test year. This net operating income provides a rate of return of 6.40 percent on the applicant's average net investment rate base of $95,727,001.

Rate Design

The Commission has a statutory responsibility to establish reasonable and just rates. It is reasonable and just to authorize flat usage and time-of-day (TOD) electric rates. The flat usage rate design provides an appropriate price signal to the consumer in lieu of TOD rates. Mandatory and/or voluntary TOD rates have been provided for all of the applicant's customers.

The rates in Appendix D are generally based on the cost-of-service principle; that is, rates are designed to recover the costs of providing service to each customer class. The applicant, CUB, WIEG, and Commission staff testified regarding COSS issues and the appropriate methods used to allocate the applicant's test year revenue requirement. The aforementioned parties and Commission staff submitted COSS results, as well as customer class revenue allocations reflecting the results of the COSS prepared by each. The COSS models presented in the record reflect a variety of different cost allocation approaches, including primary and secondary voltage allocation and classification of production plant. No consensus was reached by the parties over the course of this proceeding regarding COSS methodologies. Furthermore, the Commission is not persuaded by the evidence that any of the proposed methods are unreasonable. The Commission's long-standing practice is to consider the results of several COSS for the purposes

of allocating test-year revenue responsibility. The evidence in this proceeding supports a continuation of this practice. Therefore, the Commission finds it reasonable to consider the results of all COSS studies in the record for the purposes of class revenue requirement allocations for the test year.

Each of the parties and Commission staff also submitted a revenue allocation for the test year based on their submitted COSS model. The applicant and WIEG presented revenue allocations based on the applicant's updated revenue requirement, which indicated a 2.99 percent deficiency. CUB and Commission staff presented revenue allocations based on Commission staff's updated revenue requirement, which indicated a 2.77 percent deficiency.

Consistent with the determinations the Commission has made in prior rate proceedings and the above determination regarding cost of service, the Commission finds that it is useful to take into account the results of a number of different COSS in addition to other factors such as rate stability and customer bill impacts when making a determination on class revenue allocation in this case. Ultimately, the Commission finds it reasonable to approve the electric revenue allocation proposed by Commission staff as proposed in Ex.-PSC-Aguirre-4r2 and as adjusted for the final revenue requirement and shown in Appendix B and discussed below. Therefore, the Commission finds that this allocation facilitates a reasonable approach to rate design and follows the directionality of the COSS and promotes gradualism.

The authorized rates, as shown in Appendix B, will produce increases in revenues from all classes for the test year. The present rates and authorized rates, listed by rate class, appear in Appendix D. It is reasonable to make the changes in electric rates as shown in Appendix D that:

1. Roll the test year PCAC of $0.0652 per kWh into base rates;
2. Roll the test year BDCF of $17.689 for July and August;

3. Roll the test year BDCF of $16.337 for June and September;
4. Roll the test year BDCF of $13.202 for all other months;
5. Roll the test year BECF of $0.0321 per kWh into base rates;
6. Reflect current operating costs, the emerging competitive environment in the electric utility industry, and the customer bill impacts; and
7. Increase demand charges to better reflect capacity-related costs in the applicant's purchased power bills.

The authorized rate and rule tariffs appear in Appendices D and F, respectively.

Residential and General Service Fixed Charges

The applicant proposed increasing the fixed charge for its residential and small commercial customers in an attempt to better align fixed costs with fixed charges. Based on an analysis of fixed customer costs produced by Commission staff's COSS models, results of the basic customer cost analysis provided by the applicant, and the applicant's gradual approach to developing its proposed customer charge rates, Commission staff suggested that the Commission could find the applicant's proposed charge to be reasonable. CUB did not object to the proposed charges and noted they fall within the range of charges suggested by its analysis. Based on the testimony and evidence submitted by the applicant, CUB, and Commission staff in this proceeding, the Commission finds it reasonable to increase residential and general service fixed charges as proposed by the applicant.

The authorized residential and general service customer charges appear in Appendix D.

Non-Sufficient Fund Rates

NSF rates are charged to a customer when payment rendered for utility service is not honored by the customer's financial institution. The current approved fee is $25.00 for both the

electric and water utilities. The applicant is a combined utility that serves both electric and water customers, and the applicant includes both electric and water services on one bill. The applicant recommended that charge remain the same. The applicant also noted combined water and electric customers receive one bill for both services and if the electric customer NSF fee were to change, this may cause confusion for customers.

In its Final Decision in docket 4220-UR-127[4] the Commission found it reasonable to set an NSF charge based on actual administrative costs plus the average financial institution fee. Based on this methodology Commission staff calculated a proposed NSF rate to change from the currently authorized amount of $25.00 to $16.59.

Consistent with its past Commission orders, the Commission finds it reasonable to set the NSF charge for the electric utility to $17.00 in its OC-1 tariff. The NSF check provision appears in Appendix D.

The Commission noted that because the NSF charge under the water tariff is $25 and the higher charge controls when a customer writes a single check covering both services, combined customers would still pay $25 even if the Commission set the electric charge at $17. The gap reflects historical differences in the parameters given to water versus electric utilities for calculating NSF charges. The Commission identified that from a policy perspective as water utility tariffs come before the Commission in future proceedings, Commission staff should apply the same cost-based methodology—administrative costs plus financial institution fees, rounded to the nearest whole dollar—to water NSF charges as well.

[4] Final Decision Docket 4220-UR-127 (PSC REF#: 571113 at 13)

Commitment to Community Rider

The applicant proposed to simplify the CTC Rider by moving from the detailed breakdown of each class to a standardized rate class group, combining the residential, general, and small power service rate classes. The applicant stated this would reduce the overall number of filings as the utility would not need to file a TE docket to add new, not listed, rates to the CTC Rider. Commission staff did not oppose simplifying the CTC Rider but recommended keeping the tariff codes listed as staff believes a guide would be helpful for customers viewing this tariff. Additionally, the applicant proposed adding the Street and Security Lighting Service (Ms-1) to the CTC Rider and Commission staff had no concerns.

The Commission finds that it was not swayed by the applicant's concern about listing the rate class withing the CTC rider as the applicant could in future filings include the request to update the CTC Rider within the same docket. Therefore, the Commission finds that Commission staff's proposed changes to the CTC tariff as identified in Ex.-PSC-Aguirre-4r2, including the inclusion of the Street and Security Lighting Services (Ms-1), provides an appropriate balance of simplifying the CTC Rider as requested by the applicant while still identifying each class to avoid confusion by customers. The CTC Rider appears in Appendix F.

Cp-3 Demand Charges

The applicant proposed updating the Cp-3 billed demand rates to three decimal places to match the Base Demand Cost Factors (BDCF) rates. Commission staff did not identify any concerns with the applicant's proposal. The Commission finds the applicant's proposed update to the CP-3 billed demand rate to three decimal places to be reasonable.

Proposed Standby, Maintenance, and Displacement Power Rider (Cp-6)

The applicant proposed updating the tariff language on the Cp-6 rider from "360 hours during the On-Peak Period" to "30 On-Peak Period days." As the updated wholesale on-peak demand period changed from 12 hours to 16 hours, this update would ensure the same time period is measured. Commission staff did not identify any concerns with the applicant's proposal. The Commission finds that it is reasonable to update the wording on the Cp-6 as proposed by the applicant.

Extension Rule Changes

The applicant's current extension rules comply with Wis. Admin. Code §§ PSC 113.1001 to 113.1010. The current extension construction allowances, however, are not based on current costs and, based on data submitted at the hearing, are unreasonable and unjust. The Commission finds it reasonable to revise the applicant's construction allowances as shown in Appendix D.

Reasonableness of Rates and Rules

The rates and rules authorized by this Final Decision will require each class of customers to bear a fair and equitable portion of the applicant's total revenue requirement for the test year ending December 31, 2025. The rate and rule changes authorized by this Final Decision are reasonable and just.

Effective Date

The Commission finds it reasonable for the authorized rate and tariff changes to take effect one day after the date of service, provided that these rates and tariff provisions are made available by that date to the public at locations where customer payments are accepted, on the

utility's Internet site, or in a form and place that is otherwise readily accessible to the public. If these rate increases and tariff provisions are not made available to the public by that date, it is reasonable to require that they take effect on the date the applicant makes them available at locations where customer payments are accepted, on the utility's Internet site, or in a form and place that is otherwise readily accessible to the public.

Order

1. The authorized rate and tariff changes shall take effect one day after the date of service, provided that these rate and tariff provisions are made available by that date to the public at locations where customer payments are accepted, on the utility's Internet site, or in a form and place that is otherwise readily accessible to the public. If these rate increases and tariff provisions are not made available to the public by that day, they shall take effect on the date the applicant makes them available at locations where customer payments are accepted, on the utility's Internet site, or in a form and place that is otherwise readily accessible to the public.

2. The applicant shall amortize the $1,445,668 deferred revenue from the sale of capacity from the applicant's Elm Street CT to customers, without carrying costs over 5-years into Account 447.

3. The applicant shall make an adjustment to Account 216.2 for the year 2024 such that Account 101.2 utility plant in service contributed plant less Account 111.2 accumulated depreciation of utility plant in service contributed plant matches Account 216.2 surplus contributions.

4. The applicant shall correct the Account 302 accumulated depreciation balance in the applicant's 2024 Annual Report to reflect a 2024 first of year accumulated depreciation

balance of $26,729 for Account 302, consistent with the adjustments and findings made in this proceeding.

5. The applicant shall revise its existing rates and tariff provisions for electric service, substituting the authorized rate and tariff changes shown in Appendices D and F. These changes shall be in effect until the Commission issues an order establishing new rates and tariff provisions.

6. The annual depreciation rates specified in Appendix G are effective on the effective date of this Final Decision.

7. The applicant shall inform the Commission, in writing within 20 days of the effective date of this Final Decision, of the date that the utility makes the authorized rates and rules effective.

8. Pursuant to Wis. Stat. § 196.19, the applicant shall be deemed to have filed with the Commission the rates authorized in this Final Decision when the utility receives completed tariff sheets reflecting this Final Decision from the Commission.

9. Extension applications made before the effective date of this Final Decision and ready to receive service within 60 days following the effective date of this Final Decision shall be completed under the applicant's current rules, rather than the rules specified in Appendix D. "Ready to receive service" means having the premises in a condition to receive permanent service or having temporary service for construction purposes. The applicant shall immediately inform all parties with pending extension requests of the new rules and 60-day limitations.

10. The applicant's PCAC and PCAC2 shall be applicable each month and shall reflect the difference between monthly and test period wholesale purchased power costs.

11. The applicant shall inform each customer of the new rates as required by Wis. Admin. Code § PSC 113.0406(1)(d).

12. This Final Decision takes effect one day after the date of service.

13. Jurisdiction is retained.

Dated at Madison, Wisconsin, the 29th day of October, 2026.

By the Commission:



Cru Stubley
Secretary to the Commission

CS:MSA:dsa:jlt:DL: 02132531

Attachments

See attached Notice of Appeal Rights

Docket 2800-ER-110

PUBLIC SERVICE COMMISSION OF WISCONSIN
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NOTICE OF RIGHTS FOR REHEARING OR JUDICIAL REVIEW, THE TIMES ALLOWED FOR EACH, AND THE IDENTIFICATION OF THE PARTY TO BE NAMED AS RESPONDENT

The following notice is served on you as part of the Commission's written decision. This general notice is for the purpose of ensuring compliance with Wis. Stat. § 227.48(2), and does not constitute a conclusion or admission that any particular party or person is necessarily aggrieved or that any particular decision or order is final or judicially reviewable.

PETITION FOR REHEARING

If this decision is an order following a contested case proceeding as defined in Wis. Stat. § 227.01(3), a person aggrieved by the decision has a right to petition the Commission for rehearing within 20 days of the date of service of this decision, as provided in Wis. Stat. § 227.49. The date of service is shown on the first page. If there is no date on the first page, the date of service is shown immediately above the signature line. The petition for rehearing must be filed with the Public Service Commission of Wisconsin and served on the parties. An appeal of this decision may also be taken directly to circuit court through the filing of a petition for judicial review. It is not necessary to first petition for rehearing.

PETITION FOR JUDICIAL REVIEW

A person aggrieved by this decision has a right to petition for judicial review as provided in Wis. Stat. § 227.53. In a contested case, the petition must be filed in circuit court and served upon the Public Service Commission of Wisconsin within 30 days of the date of service of this decision if there has been no petition for rehearing. If a timely petition for rehearing has been filed, the petition for judicial review must be filed within 30 days of the date of service of the order finally disposing of the petition for rehearing, or within 30 days after the final disposition of the petition for rehearing by operation of law pursuant to Wis. Stat. § 227.49(5), whichever is sooner. If an *untimely* petition for rehearing is filed, the 30-day period to petition for judicial review commences the date the Commission serves its original decision.[5] The Public Service Commission of Wisconsin must be named as respondent in the petition for judicial review.

If this decision is an order denying rehearing, a person aggrieved who wishes to appeal must seek judicial review rather than rehearing. A second petition for rehearing is not permitted.

Revised: March 27, 2013

[5] *See Currier v. Wisconsin Dep't of Revenue,* 2006 WI App 12, 288 Wis. 2d 693, 709 N.W.2d 520.

APPENDIX A

PUBLIC SERVICE COMMISSION OF WISCONSIN
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Docket 2800-ER-110

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Docket 2800-ER-110
Kaukauna Utilities

Final Form Rate and Rule Tariff Sheets
Amendment

Filed By:
Public Service Commission of Wisconsin

Kaukauna Utilities
COMPARATIVE INCOME STATEMENT
TEST YEAR ENDED DECEMBER 31, 2025

	Present Rates*	Authorized Rates	Dollar Change	Percent Change
OPERATING REVENUES				
RETAIL SALES OF ELECTRICITY				
Residential Service	15,944,881	$16,519,660	574,779	3.60%
General Service	4,109,353	$4,218,927	109,574	2.67%
Small Power Service	$3,928,357	$3,931,412	3,056	0.08%
CP-2	12,245,864	$12,808,759	562,895	4.60%
CP-3	17,339,748	$17,624,259	284,511	1.64%
NLMP CP-2	736,667	$745,762	9,095	1.23%
CP-6 Standby Service	$1,144,265	$1,144,265		
Lighting Service	507,789	$511,539	3,750	0.74%
TOTAL RETAIL SALES OF ELECTRICITY	55,956,924	57,504,583	1,547,660	2.77%
*/ Reflects a Test Year PCAC of $0.0071 per kWh.				
OTHER SALES OF ELECTRICITY	2,041,883	2,041,883	-	0.00%
TOTAL ALL SALES OF ELECTRICITY	57,998,807	$59,546,466	1,547,660	2.67%
OTHER OPERATING REVENUE				
Forfeited Discounts	78,048	78,048		
Miscellaneous Service Revenue	18,861	18,861		
Sales of Water & Water Power	-	-		
Rent from Electric Property	231,000	231,000		
Interdepartmental Rents	9,702	9,702		
Other Electric Revenues	189,006	189,006		
TOTAL OTHER OPERATING REVENUES	526,617	526,617		
TOTAL ALL OPERATING REVENUES (A)	58,525,424	$60,073,083		
OPERATING EXPENSE				
O. & M. EXPENSE				
Production Expense				
Purchased Power Expense (80.91% of O&M)	36,932,339	36,932,339		
Generation Expenses	1,939,250	1,939,250		
Total Production Expenses	38,871,589	38,871,589		
Trans. & Distrib. Expenses	2,261,950	2,261,950		
Customer Account & Sales Expenses	660,391	660,391		
Admin. & General Expenses	3,854,669	3,854,669		
TOTAL O. & M. EXPENSE	45,648,599	45,648,599		
DEPRECIATION EXPENSE	5,241,530	5,241,530		
AMORTIZATION EXPENSE	-	-		
TAXES OTHER THAN INCOME	3,056,494	3,056,494		
INCOME TAXES	-	-		
TOTAL OPERATING EXPENSES (B)	53,946,623	53,946,623		
NET OPERATING INCOME (A-B = C)	4,578,801	$6,126,460		
AVG. NET INVEST. RATE BASE (D)	95,727,001	95,727,001		
RATE OF RETURN ON RATE BASE(C/ D)	4.78%	6.40%		

Kaukauna Utilities
ELECTRIC RETAIL REVENUE ALLOCATION SUMMARY
TEST YEAR ENDED DECEMBER 31, 2025

	RATE CLASS	TEST YEAR KWH	PRESENT REVENUES	AUTHORIZED REVENUES	AUTHORIZED DOLLAR INCREASE	AUTHORIZED PERCENT INCREASE	PSC STAFF COSS PERCENT INCREASE
RG-1	Residential Service	123,726,907	$15,896,706	$16,467,414	$570,708	3.59%	4.08%
RG-2	Residential Optional Time-of-Day Service	408,316	$48,175	$52,246	$4,071	8.45%	8.79%
RG-3	Residential Optional Three Tier Time-of-Day Service	0	$0	$0	$0	0.00%	0.00%
	TOTAL RESIDENTIAL	124,135,223	$15,944,881	$16,519,660	$574,779	3.60%	4.09%
GS-1	General Service	30,618,381	$3,925,841	$4,025,631	$99,790	2.54%	3.51%
GS-2	General Service Optional Time-of-Day	1,608,324	$183,512	$193,296	$9,784	5.33%	-6.01%
	TOTAL GENERAL SERVICE	32,226,705	$4,109,353	$4,218,927	$109,574	2.67%	3.08%
CP-1	Small Power Service (50-200 kW)	34,259,435	$3,752,591	$3,755,646	$3,056	0.08%	-1.62%
CP-1 TOU	Small Power Optional Time-of-Day Service (50-200 k'	1,724,012	$175,766	$175,766	$0	0.00%	-10.09%
	TOTAL SMALL COMMERCIAL & INDUSTRIAL	35,983,447	$3,928,357	$3,931,412	$3,056	0.08%	-2.00%
CP-2	Large Power Service (200-5000 kW)	143,206,889	$12,245,864	$12,808,759	$562,895	4.60%	5.21%
CP-2 NLMP	New Load Market Pricing Service	15,562,600	$736,667	$745,762	$9,095	1.23%	0.00%
CP-3	Industrial Power Service (>5000 kW)	221,888,825	$17,339,748	$17,624,259	$284,511	1.64%	1.90%
Cp-6	Standby, Maintenance, and Displacement Power Rider	218,138	$1,144,265	$1,144,265	$0	0.00%	0.00%
	TOTAL LARGE COMMERCIAL & INDUSTRIAL	380,876,452	$31,466,544	$32,323,045	$856,501	2.72%	3.08%
MS-1	Street Lighting Service	1,250,000	$507,789	$511,539	$3,750	0.74%	0.00%
	TOTAL LIGHTING SERVICE	1,250,000	$507,789	$511,539	$3,750	0.74%	-13.60%
TOTAL ELECTRIC RETAIL REVENUE		574,471,827	$55,956,924	$57,504,583	$1,547,660	2.77%	2.77%

Kaukauna Utilities
PRESENT AND AUTHORIZED RATES
TEST YEAR ENDED DECEMBER 31, 2025

Type of Service		Present Rates		Authorized Rates	
Residential Service Rg-1					
Customer Charge					
	Single Phase	$ 13.00	per month	$ 15.00	per month
	Three Phase	$ 25.00	per month	$ 25.00	per month
Energy Charge		$ 0.1007	per kWh	$ 0.1120	per kWh
PCAC		$ 0.0095	per kWh	$ -	per kWh
Residential Optional Time-of-Day Service Rg-2					
Customer Charge					
	Single Phase	$ 13.00	per month	$ 15.00	per month
	Three Phase	$ 25.00	per month	$ 25.00	per month
Energy Charge					
	On-Peak kWh	$ 0.1729	per kWh	$ 0.1994	per kWh
	Off-Peak kWh	$ 0.0640	per kWh	$ 0.0774	per kWh
PCAC		$ 0.0095	per kWh	$ -	per kWh
Residential Optional Three Tier Time-of-Day Service Rg-3					
Customer Charge					
	Single Phase	$ 13.00	per month	$ 15.00	per month
	Three Phase	$ 25.00	per month	$ 25.00	per month
Energy Charge					
	On-Peak kWh	$ 0.1499	per kWh	$ 0.1755	per kWh
	Standard Hours kWh	$ 0.1007	per kWh	$ 0.1120	per kWh
	Off-Peak kWh	$ 0.0623	per kWh	$ 0.0605	per kWh
PCAC		$ 0.0095	per kWh	$ -	per kWh
General Service Gs-1					
Customer Charge					
	Single Phase	$ 16.00	per month	$ 18.00	per month
	Three Phase	$ 25.00	per month	$ 27.00	per month
Energy Charge		$ 0.1063	per kWh	$ 0.1177	per kWh
PCAC		$ 0.0095	per kWh	$ -	per kWh
General Service Optional Time-of-Day Gs-2					
Customer Charge					
	Single Phase	$ 16.00	per month	$ 18.00	per month
	Three Phase	$ 25.00	per month	$ 27.00	per month
Energy Charge					
	On-Peak kWh	$ 0.1879	per kWh	$ 0.2052	per kWh
	Off-Peak kWh	$ 0.0563	per kWh	$ 0.0697	per kWh
PCAC		$ 0.0095	per kWh	$ -	per kWh

Kaukauna Utilities
PRESENT AND AUTHORIZED RATES
TEST YEAR ENDED DECEMBER 31, 2025

Type of Service	Present Rates	Authorized Rates
Small Power Service CP-1 (50-200 kW)		
Customer Charge	$ 50.00 per month	$ 50.00 per month
Distribution Demand Charge	$ 1.50 per kW	$ 1.50 per kW
Monthly Billed Demand Charge	$ 9.00 per kW	$ 9.00 per kW
Energy Charge	$ 0.0594 per kWh	$ 0.0690 per kWh
Rate Limiter	$ 0.1208 per kWh	$ 0.1303 per kWh
PCAC	$ 0.0095 per kWh	$ - per kWh
Primary Voltage Discount		
All Voltage Levels (1)	0.00% per $	0.00% per $
2.3-15 kV (2)	-2.00% per $	-2.00% per $
>15 kV (3)	-3.00% per $	-3.00% per $
Transformer Ownership Discount on Distribution Demand		
All Voltage Levels (A)	$ - per kW	$ - per kW
2.3-15 kV (B)	$ (0.200) per kW	$ (0.200) per kW
>15 kV (C)	$ (0.400) per kW	$ (0.400) per kW
Small Power Optional Time-of-Day Service CP-1 TOU (50-200 kW)		
Customer Charge	$ 50.00 per month	$ 50.00 per month
Distribution Demand Charge	$ 1.50 per kW	$ 1.50 per kW
Monthly Billed Demand Charge	$ 9.00 per kW	$ 9.00 per kW
Energy Charge		
On-Peak kWh	$ 0.0743 per kWh	$ 0.0838 per kWh
Off-Peak kWh	$ 0.0516 per kWh	$ 0.0611 per kWh
PCAC	$ 0.0095 per kWh	$ - per kWh
Primary Voltage Discount		
All Voltage Levels (1)	0.00% per $	0.00% per $
2.3-15 kV (2)	-2.00% per $	-2.00% per $
>15 kV (3)	-3.00% per $	-3.00% per $
Transformer Ownership Discount on Distribution Demand		
All Voltage Levels (A)	$ - per kW	$ - per kW
2.3-15 kV (B)	$ (0.2000) per kW	$ (0.2000) per kW
>15 kV (C)	$ (0.4000) per kW	$ (0.4000) per kW

Kaukauna Utilities
PRESENT AND AUTHORIZED RATES
TEST YEAR ENDED DECEMBER 31, 2025

Type of Service		Present Rates		Authorized Rates	
Large Power Service CP-2 (200-5000 kW)					
Customer Charge		$ 100.00	per month	$ 100.00	per month
Distribution Demand Charge		$ 1.75	per kW	$ 2.00	per kW
Monthly Billed Demand Charge		$ 10.25	per kW	$ 10.50	per kW
Energy Charge					
	On-Peak kWh	$ 0.0577	per kWh	$ 0.0700	per kWh
	Off-Peak kWh	$ 0.0390	per kWh	$ 0.0513	per kWh
PCAC		$ 0.0095	per kWh	$ -	per kWh
Primary Voltage Discount					
All Voltage Levels (1)		0.00%	per $	0.00%	per $
2.3-15 kV (2)		-2.00%	per $	-2.00%	per $
>15 kV (3)		-3.00%	per $	-3.00%	per $
Transformer Ownership Discount on Distribution Demand					
All Voltage Levels (A)		$ -	per kW	$ -	per kW
2.3-15 kV (B)		$ (0.2000)	per kW	$ (0.2000)	per kW
>15 kV (C)		$ (0.4000)	per kW	$ (0.4000)	per kW
Industrial Power Service CP-3 (>5000 kW)					
Customer Charge		$ 300.00	per month	$ 300.00	per month
Distribution Demand Charge		$ 1.75	per kW	$ 1.75	per kW
July/August Billed Demand Charge		$ 17.900	per kW	$ 17.698	per kW
June/September Billed Demand Charge		$ 13.500	per kW	$ 16.337	per kW
Other Months Billed Demand Charge		$ 12.800	per kW	$ 13.202	per kW
Energy Charge					
	On-Peak kWh	$ 0.0461	per kWh	$ 0.0573	per kWh
	Off-Peak kWh	$ 0.0327	per kWh	$ 0.0439	per kWh
ECA		$ 0.0095	per kWh	$ -	per kWh
Peak DCA		$ (0.1080)	per kWh		per kWh
Shoulder DCA		$ 2.8580	per kWh		per kWh
All Other DCA		$ 0.4750	per kW		per kW
Primary Voltage Discount					
All Voltage Levels (1)		0.00%	per $	0.00%	per $
2.3-15 kV (2)		-2.00%	per $	-2.00%	per $
>15 kV (3)		-3.00%	per $	-3.00%	per $
Transformer Ownership Discount on Distribution Demand					
All Voltage Levels (A)		$ -	per kW	$ -	per kW
2.3-15 kV (B)		$ (0.2000)	per kW	$ (0.2000)	per kW
>15 kV (C)		$ (0.4000)	per kW	$ (0.4000)	per kW

Kaukauna Utilities
PRESENT AND AUTHORIZED RATES
TEST YEAR ENDED DECEMBER 31, 2025

Type of Service	Present Rates	Authorized Rates
Street Lighting Service MS-1		
INVESTMENT CHARGE		
Overhead		
25-75 W LED	$9.50 per month	$9.50 per month
76-150 W LED	$10.25 per month	$10.25 per month
150 W LED	$13.00 per month	$13.00 per month
100 W HPS	$9.50 per month	$9.50 per month
250 W HPS	$10.25 per month	$10.25 per month
400 W HPS	$12.00 per month	$12.00 per month
400 W HPS Wide Light	$12.50 per month	$12.50 per month
Ornamental		
25-75 W LED	$15.00 per month	$15.00 per month
76-150 W LED	$15.50 per month	$15.50 per month
150 W LED	$16.00 per month	$16.00 per month
100 W HPS	$13.50 per month	$13.50 per month
150 W HPS	$14.00 per month	$14.00 per month
250 W HPS	$14.50 per month	$14.50 per month
400 W HPS	$15.00 per month	$15.00 per month
Security		
25-75 W LED	$10.00 per month	$10.00 per month
76-150 W LED	$11.00 per month	$11.00 per month
150 W LED	$12.50 per month	$12.50 per month
100 W HPS	$10.50 per month	$10.50 per month
100 W HPS Ornamental	$14.00 per month	$14.00 per month
250 W HPS	$11.00 per month	$11.00 per month
400 W HPS	$12.00 per month	$12.00 per month
400 W HPS Wide Light	$13.00 per month	$13.00 per month
400 W HPS Ornamental	$16.25 per month	$16.25 per month
Customer Charge	$ - per month	$ - per month
Distribution Demand Charge	$ - per kW	$ - per kW
Energy Charge	$ 0.0679 per kWh	$ 0.0804 per kWh
PCAC	$ 0.0095 per kWh	$ - per kWh

Kaukauna Utilities
PRESENT AND AUTHORIZED RATES
TEST YEAR ENDED DECEMBER 31, 2025

Type of Service	Present Rates	Authorized Rates
AVERAGE BASE COST OF POWER		
PCAC	$ 0.0557 per kWh	$ 0.0652 per kWh
PCAC2 - BDCF - July/August	$ 17.806 per kW	$ 17.698 per kW
PCAC2 - BDCF - June/September	$ 13.479 per kW	$ 16.337 per kW
PCAC2 - BDCF - All Other Months	$ 12.727 per kW	$ 13.202 per kW
PCAC2 - BECF	$ 0.0226 per kWh	$ 0.0321 per kWh
EMBEDDED COST ALLOWANCES		
Rg-1 & Rg-2, $/Customer	$ 689.00	$ 607.58
Gs-1 & Gs-2, $/Customer	$ 1,370.00	$ 1,396.49
Cp-1 & Cp-1 TOD, $/kW-mo	$ 180.00	$ 171.35
Cp-2, $/kW-mo	$ 103.00	$ 89.41
Cp-3, $/kW-mo	$ 58.00	$ 71.89
Cp-4, $/kW-mo	$ -	$ -
Ms-1, $/Lamp	$ 23.00	$ 17.38
NSF CHARGE	$ 25.00	$ 17.00
RECONNECTION CHARGES		
During Office Hours	$ 45.00	$ 45.00
After Office Hours	$ 80.00	$ 80.00

Kaukauna Utilities
DETAILED BILL IMPACT ANALYSIS: RESIDENTIAL & GENERAL SERVICE
TEST YEAR ENDED DECEMBER 31, 2025

Residential Service Rg-1: Single Phase

Monthly kWh	Monthly Bills		Authorized Increase	
	Current Rates	Proposed Rates	$ Amount	% Change
100	$24.02	$26.20	$2.18	9.08%
500	$68.10	$71.00	$2.90	4.26%
750	$95.65	$99.00	$3.35	3.50%
1,000	$123.20	$127.00	$3.80	3.08%
1,500	$178.30	$183.00	$4.70	2.64%
2,500	$288.50	$295.00	$6.50	2.25%
4,000	$453.80	$463.00	$9.20	2.03%
711	**$91.36**	**$94.64**	**$3.28**	**3.59%**

Residential Service Rg-1: Three Phase

Monthly kWh	Monthly Bills		Authorized Increase	
	Current Rates	Proposed Rates	$ Amount	% Change
100	$36.02	$36.20	$0.18	0.50%
500	$80.10	$81.00	$0.90	1.12%
750	$107.65	$109.00	$1.35	1.25%
1,000	$135.20	$137.00	$1.80	1.33%
1,500	$190.30	$193.00	$2.70	1.42%
2,500	$300.50	$305.00	$4.50	1.50%
4,000	$465.80	$473.00	$7.20	1.55%
711	**$103.36**	**$104.64**	**$1.28**	**1.24%**

* Values in bold represent class average usage

Residential Optional Time-of-Day Service Rg-2: Single Phase

25% On-Peak Usage

Monthly kWh	Monthly Bills		Authorized Increase	
	Current Rates	Proposed Rates	$ Amount	% Change
100	$23.07	$25.79	$2.72	11.78%
500	$63.36	$68.95	$5.59	8.82%
750	$88.54	$95.93	$7.38	8.34%
1,000	$113.73	$122.90	$9.18	8.07%
1,500	$164.09	$176.85	$12.76	7.78%
2,500	$264.81	$284.75	$19.94	7.53%
4,000	$415.90	$446.60	$30.70	7.38%

Kaukauna Utilities
DETAILED BILL IMPACT ANALYSIS: RESIDENTIAL & GENERAL SERVICE
TEST YEAR ENDED DECEMBER 31, 2025

Residential Optional Time-of-Day Service Rg-2: Single Phase

30% On-Peak Usage

Monthly	Monthly Bills		Authorized Increase	
kWh	Current Rates	Proposed Rates	$ Amount	% Change
100	$23.62	$26.40	$2.78	11.78%
500	$66.09	$72.00	$5.91	8.95%
750	$92.63	$100.50	$7.87	8.50%
1,000	$119.17	$129.00	$9.83	8.25%
1,500	$172.26	$186.00	$13.75	7.98%
2,500	$278.43	$300.00	$21.58	7.75%
4,000	$437.68	$471.00	$33.32	7.61%

Residential Optional Time-of-Day Service Rg-2: Single Phase

35% On-Peak Usage

Monthly	Monthly Bills		Authorized Increase	
kWh	Current Rates	Proposed Rates	$ Amount	% Change
100	$24.16	$27.01	$2.85	11.79%
500	$68.81	$75.05	$6.24	9.07%
750	$96.71	$105.08	$8.36	8.65%
1,000	$124.62	$135.10	$10.49	8.41%
1,500	$180.42	$195.15	$14.73	8.16%
2,500	$292.04	$315.25	$23.21	7.95%
4,000	$459.46	$495.40	$35.94	7.82%

Residential Optional Time-of-Day Service Rg-2: Single Phase

40% On-Peak Usage

Monthly	Monthly Bills		Authorized Increase	
kWh	Current Rates	Proposed Rates	$ Amount	% Change
100	$24.71	$27.62	$2.91	11.79%
500	$71.53	$78.10	$6.57	9.18%
750	$100.80	$109.65	$8.85	8.79%
1,000	$130.06	$141.20	$11.14	8.57%
1,500	$188.59	$204.30	$15.71	8.33%
2,500	$305.65	$330.50	$24.85	8.13%
4,000	$481.24	$519.80	$38.56	8.01%

Kaukauna Utilities
DETAILED BILL IMPACT ANALYSIS: RESIDENTIAL & GENERAL SERVICE
TEST YEAR ENDED DECEMBER 31, 2025

Residential Optional Time-of-Day Service Rg-2: Single Phase

45% On-Peak Usage

Monthly	Monthly Bills		Authorized Increase	
kWh	Current Rates	Proposed Rates	$ Amount	% Change
100	$25.25	$28.23	$2.98	11.80%
500	$74.25	$81.15	$6.90	9.29%
750	$104.88	$114.23	$9.35	8.91%
1,000	$135.51	$147.30	$11.80	8.70%
1,500	$196.76	$213.45	$16.69	8.48%
2,500	$319.26	$345.75	$26.49	8.30%
4,000	$503.02	$544.20	$41.18	8.19%

Residential Optional Time-of-Day Service Rg-2: Single Phase

50% On-Peak Usage

Monthly	Monthly Bills		Authorized Increase	
kWh	Current Rates	Proposed Rates	$ Amount	% Change
100	$25.80	$28.84	$3.05	11.80%
500	$76.98	$84.20	$7.22	9.39%
750	$108.96	$118.80	$9.84	9.03%
1,000	$140.95	$153.40	$12.45	8.83%
1,500	$204.93	$222.60	$17.68	8.63%
2,500	$332.88	$361.00	$28.13	8.45%
4,000	$524.80	$568.60	$43.80	8.35%

General Service Gs-1: Single Phase

Monthly	Monthly Bills		Authorized Increase	
kWh	Current Rates	Proposed Rates	$ Amount	% Change
500	$73.90	$76.85	$2.95	3.99%
1,000	$131.80	$135.70	$3.90	2.96%
2,000	$247.60	$253.40	$5.80	2.34%
3,000	$363.40	$371.10	$7.70	2.12%
4,000	$479.20	$488.80	$9.60	2.00%
5,000	$595.00	$606.50	$11.50	1.93%
6,000	$710.80	$724.20	$13.40	1.89%
1,471	**$186.40**	**$191.19**	**$4.80**	**2.57%**

Kaukauna Utilities
DETAILED BILL IMPACT ANALYSIS: RESIDENTIAL & GENERAL SERVICE
TEST YEAR ENDED DECEMBER 31, 2025

General Service Gs-1: Three Phase

Monthly	Monthly Bills		Authorized Increase	
kWh	Current Rates	Proposed Rates	$ Amount	% Change
500	$82.90	$85.85	$2.95	3.56%
1,000	$140.80	$144.70	$3.90	2.77%
2,000	$256.60	$262.40	$5.80	2.26%
3,000	$372.40	$380.10	$7.70	2.07%
4,000	$488.20	$497.80	$9.60	1.97%
5,000	$604.00	$615.50	$11.50	1.90%
6,000	$719.80	$733.20	$13.40	1.86%
1,471	**$195.40**	**$200.19**	**$4.80**	**2.45%**

* Values in bold represent class average usage

General Service Optional Time-of-Day Gs-2: Single Phase

30% On-Peak Usage

Monthly	Monthly Bills		Authorized Increase	
kWh	Current Rates	Proposed Rates	$ Amount	% Change
500	$68.64	$73.18	$4.54	6.61%
1,000	$121.28	$128.35	$7.07	5.83%
2,000	$226.56	$238.70	$12.14	5.36%
3,000	$331.84	$349.05	$17.21	5.19%
4,000	$437.12	$459.40	$22.28	5.10%
5,000	$542.40	$569.75	$27.35	5.04%
6,000	$647.68	$680.10	$32.42	5.01%

General Service Optional Time-of-Day Gs-2: Single Phase

35% On-Peak Usage

Monthly	Monthly Bills		Authorized Increase	
kWh	Current Rates	Proposed Rates	$ Amount	% Change
500	$71.93	$76.56	$4.63	6.44%
1,000	$127.86	$135.13	$7.27	5.68%
2,000	$239.72	$252.25	$12.53	5.23%
3,000	$351.58	$369.38	$17.80	5.06%
4,000	$463.44	$486.50	$23.06	4.98%
5,000	$575.30	$603.63	$28.32	4.92%
6,000	$687.16	$720.75	$33.59	4.89%

Kaukauna Utilities
DETAILED BILL IMPACT ANALYSIS: RESIDENTIAL & GENERAL SERVICE
TEST YEAR ENDED DECEMBER 31, 2025

General Service Optional Time-of-Day Gs-2: Single Phase

40% On-Peak Usage

Monthly	Monthly Bills		Authorized Increase	
kWh	Current Rates	Proposed Rates	$ Amount	% Change
500	$75.22	$79.95	$4.73	6.29%
1,000	$134.44	$141.90	$7.46	5.55%
2,000	$252.88	$265.80	$12.92	5.11%
3,000	$371.32	$389.70	$18.38	4.95%
4,000	$489.76	$513.60	$23.84	4.87%
5,000	$608.20	$637.50	$29.30	4.82%
6,000	$726.64	$761.40	$34.76	4.78%

General Service Optional Time-of-Day Gs-2: Single Phase

45% On-Peak Usage

Monthly	Monthly Bills		Authorized Increase	
kWh	Current Rates	Proposed Rates	$ Amount	% Change
500	$78.51	$83.34	$4.83	6.15%
1,000	$141.02	$148.68	$7.66	5.43%
2,000	$266.04	$279.35	$13.31	5.00%
3,000	$391.06	$410.03	$18.96	4.85%
4,000	$516.08	$540.70	$24.62	4.77%
5,000	$641.10	$671.38	$30.28	4.72%
6,000	$766.12	$802.05	$35.93	4.69%

General Service Optional Time-of-Day Gs-2: Single Phase

50% On-Peak Usage

Monthly	Monthly Bills		Authorized Increase	
kWh	Current Rates	Proposed Rates	$ Amount	% Change
500	$81.80	$86.73	$4.93	6.02%
1,000	$147.60	$155.45	$7.85	5.32%
2,000	$279.20	$292.90	$13.70	4.91%
3,000	$410.80	$430.35	$19.55	4.76%
4,000	$542.40	$567.80	$25.40	4.68%
5,000	$674.00	$705.25	$31.25	4.64%
6,000	$805.60	$842.70	$37.10	4.61%

Kaukauna Utilities
DETAILED BILL IMPACT ANALYSIS: RESIDENTIAL & GENERAL SERVICE
TEST YEAR ENDED DECEMBER 31, 2025

General Service Optional Time-of-Day Gs-2: Single Phase

55% On-Peak Usage

Monthly	Monthly Bills		Authorized Increase	
kWh	Current Rates	Proposed Rates	$ Amount	% Change
500	$85.09	$90.11	$5.02	5.90%
1,000	$154.18	$162.23	$8.05	5.22%
2,000	$292.36	$306.45	$14.09	4.82%
3,000	$430.54	$450.68	$20.13	4.68%
4,000	$568.72	$594.90	$26.18	4.60%
5,000	$706.90	$739.13	$32.22	4.56%
6,000	$845.08	$883.35	$38.27	4.53%

General Service Optional Time-of-Day Gs-2: Single Phase

60% On-Peak Usage

Monthly	Monthly Bills		Authorized Increase	
kWh	Current Rates	Proposed Rates	$ Amount	% Change
500	$88.38	$93.50	$5.12	5.79%
1,000	$160.76	$169.00	$8.24	5.13%
2,000	$305.52	$320.00	$14.48	4.74%
3,000	$450.28	$471.00	$20.72	4.60%
4,000	$595.04	$622.00	$26.96	4.53%
5,000	$739.80	$773.00	$33.20	4.49%
6,000	$884.56	$924.00	$39.44	4.46%

General Service Optional Time-of-Day Gs-2: Single Phase

65% On-Peak Usage

Monthly	Monthly Bills		Authorized Increase	
kWh	Current Rates	Proposed Rates	$ Amount	% Change
500	$91.67	$96.89	$5.22	5.69%
1,000	$167.34	$175.78	$8.44	5.04%
2,000	$318.68	$333.55	$14.87	4.67%
3,000	$470.02	$491.33	$21.30	4.53%
4,000	$621.36	$649.10	$27.74	4.46%
5,000	$772.70	$806.88	$34.18	4.42%
6,000	$924.04	$964.65	$40.61	4.39%

Kaukauna Utilities
DETAILED BILL IMPACT ANALYSIS: RESIDENTIAL & GENERAL SERVICE
TEST YEAR ENDED DECEMBER 31, 2025

General Service Optional Time-of-Day Gs-2: Single Phase

70% On-Peak Usage

Monthly	Monthly Bills		Authorized Increase	
kWh	Current Rates	Proposed Rates	$ Amount	% Change
500	$94.96	$100.28	$5.31	5.60%
1,000	$173.92	$182.55	$8.63	4.96%
2,000	$331.84	$347.10	$15.26	4.60%
3,000	$489.76	$511.65	$21.89	4.47%
4,000	$647.68	$676.20	$28.52	4.40%
5,000	$805.60	$840.75	$35.15	4.36%
6,000	$963.52	$1,005.30	$41.78	4.34%

Authorized Rate and Rule Tariff Sheets

Power Cost Adjustment Clause

All metered rates shall be subject to a positive or negative power cost adjustment charge equivalent to the amount by which the current cost of power (per kilowatt-hour of sales) is greater or lesser than the base cost of power purchased and produced (per kilowatt-hour of sales).

The current cost per kilowatt-hour of energy billed is equal to the cost of power purchased and produced for the most recent month, divided by the kilowatt-hours of energy sold. The monthly adjustment (rounded to the nearest one one-hundredth of a cent) is equal to the current cost less the base cost. The base cost of power (U) is $0.0652 per kilowatt-hour.

Periodic changes shall be made to maintain the proper relative structure of the rates and to insure that power costs are being equitably recovered from the various rate classes. If the monthly adjustment (A) exceeds $0.0150 per kilowatt-hour, for more than three times in a 12-month period (current plus preceding 11-months), the company shall notify the Public Service Commission of Wisconsin separate from its monthly PCAC report of the need to evaluate a change in rates to incorporate a portion of the power cost adjustment into the base rates.

For purposes of calculating the power cost adjustment charge, the following formula shall be used:

$$A = \frac{C}{S} - U$$

A is the power cost adjustment rate in dollars per kilowatt-hour rounded to four decimal places applied on a per kilowatt-hour basis to all metered sales of electricity.

S is the total kilowatt-hours sold during the most recent month.

U is the base cost of power, which equals the average cost of power purchased and produced per kilowatt-hour of sales for the test year period. This figure remains constant in each subsequent monthly calculation at $0.0652 per kilowatt-hour until otherwise changed by the Public Service Commission of Wisconsin.

C is the cost of power purchased and produced in dollars in the most recent month. Cost of power purchased and produced for calculation of C are the monthly amounts which would be recorded in the following accounts of the Uniform System of Accounts:

Class A & B utilities	Accounts 501, 536, 547 and 555
Class C utilities	Accounts 501, 531, 539 and 545

Power Cost Adjustment Clause 2

This schedule applies to service for the Cp-3 tariff. The cost of power and sales referred to in this schedule include only those for Cp-3 service.

All Cp-3 metered rates shall be subject to a positive or negative demand cost adjustment and energy cost adjustment clauses equivalent to the amount by which the current demand-related and energy-related costs of purchased or produced power are greater or lesser than the base demand-related and energy-related costs of power.

Demand Cost Adjustment (DCA)

The current cost per kilowatt of demand billed is equal to the current Cp-3 wholesale demand-related cost of purchased or produced power for the most recent month, divided by the retail kilowatts of demand sold to the Cp-3 customers. The monthly demand cost adjustment (DCA), rounded to the nearest one-tenth of a cent, is equal to the current cost less the Base Demand Cost Factor (BDCF).

For purposes of calculating the DCA charge, the following formula shall be used:

$$\text{DCA} = \frac{\text{WDC}}{\text{RBD}} - \text{BDCF}$$

DCA is the current average demand-related adjustment rate in dollars per kilowatt rounded to three decimal places applied on a per kilowatt basis to all Cp-3 customers' maximum on-peak billing demands.

WDC is the current demand-related cost of power purchased or produced on behalf of Cp-3 customers (in dollars) in the most recent month. Demand-related costs include the facilities charge and any demand-related charges.

RBD is the retail on-peak billing demands of the Cp-3 customers in the most recent month.

BDCF is the Base Demand Cost Factor, which equals the average demand cost of power purchased or produced per kilowatt for the test period. The following values will be used until otherwise changed by the Public Service Commission of Wisconsin:

$17.698 per kilowatt	(July & August)
$16.337 per kilowatt	(June & September)
$13.202 per kilowatt	(all other months)

(Continued on next page)

Power Cost Adjustment Clause 2

Energy Cost Adjustment (ECA)

The current cost per kilowatt-hour of energy billed is equal to the current Cp-3 wholesale energy-related cost of purchased or produced power for the most recent month, divided by the retail kilowatt-hours of energy sold to the Cp-3 customers. The monthly energy cost adjustment (ECA), rounded to the nearest one-hundredth of a cent, is equal to the current cost less the Base Energy Cost Factor (BECF). The BECF is $0.0321 per kilowatt-hour.

For purposes of calculating the ECA charge, the following formula shall be used:

$$\text{ECA} = \frac{\text{WEC}}{\text{RE}} - \text{BECF}$$

ECA is the current average energy-related adjustment rate in dollars per kilowatt-hour rounded to four decimal places applied on a per kilowatt basis to all Cp-3 metered sales of electricity.

WEC is the current energy-related cost of power purchased or produced on behalf of Cp-3 customers (in dollars) in the most recent month. Energy-related costs any energy-related cost components plus any reactive energy charges.

RE is the total kilowatt-hours sold to Cp-3 customers in the most recent month.

BECF is the Base Energy Cost Factor, which equals the average energy cost of power purchased or produced per kilowatt-hour for the test period. This figure remains constant in each subsequent monthly calculation at $0.0321 per kilowatt-hour until otherwise changed by the Public Service Commission of Wisconsin.

RATE FILE

Sheet No. 1 of 1
Schedule No. Rg-1
Amendment No. APDX

Public Service Commission of Wisconsin

KAUKAUNA UTILITY

Residential Service

Application: This rate will be applied to residential single-phase customers for ordinary household purposes. Single-phase motors may not exceed 5 horsepower individual-rated capacity without utility permission.

Customers who do not meet these criteria will be served under the applicable rate.

Customer Charge: Single-phase: $15.00 per month.

Three-phase: $25.00 per month.

Energy Charge: $0.1120 per kilowatt-hour (kWh).

Power Cost Adjustment Clause: Charge per all kWh varies monthly. See schedule PCAC.

Minimum Monthly Bill: The minimum monthly bill shall be the customer charge.

Prompt Payment of Bills: A charge of no more than 1 percent per month will be added to bills not paid within 20 days from date of issuance. The late payment charge shall be applied to the total unpaid balance for utility service, including unpaid payment charges. This charge is applicable to all customers.

EFFECTIVE:
PSCW AUTHORIZATION:

RATE FILE

Sheet No.	1 of 1
Schedule No.	Rg-2
Amendment No.	APDX

Public Service Commission of Wisconsin

KAUKAUNA UTILITY

Residential Service – Optional Time of Day

Application: This rate schedule is optional to all Rg-1, Residential Service customers. Customers that wish to be served on this rate schedule must apply to the utility for service. Once an optional customer begins service on this rate schedule, the customer shall remain on the rate for a minimum of one year. Any customer choosing to be served on this rate schedule waives all rights to billing adjustments arising from a claim that the bill for service would be less on another rate schedule than under this rate schedule.

Once on this rate, the utility will review billing annually according to Wis. Admin. Code ch. PSC 113.

Customer Charge: Single-phase: $15.00 per month.
Three-phase: $25.00 per month.

Energy Charge: On-peak: $0.1994 per kilowatt-hour (kWh).
Off-peak: $0.0774 per kWh.

Power Cost Adjustment Clause: Charge per all kWh varies monthly. See schedule PCAC.

Pricing Periods: On-peak: The three on-peak periods available are:
7:00 a.m. to 7:00 p.m. (closed to new customers)
8:00 a.m. to 8:00 p.m.
9:00 a.m. to 9:00 p.m. (closed to new customers)
Monday through Friday, excluding holidays, specified below.

Off-peak: All times not specified as on-peak including all day Saturday and Sunday, and the following holidays: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day, or the day designated to be celebrated as such.

Prompt Payment of Bills: Same as Rg-1.

Minimum Monthly Bill: The minimum monthly bill shall be the customer charge.

Moving Provision: If a customer moves within the utility's service territory, both the original and the new customer have the option to retain time-of-day billing or to transfer to the Residential Service rate, Rg-1, at no cost to the customer.

Joint Residential/Commercial Customers: A customer occupying a building or apartment for residential and commercial purposes jointly shall be billed on another rate which is determined based on the customer's load.

RATE FILE

Sheet No.	1 of 1
Schedule No.	Rg-3
Amendment No.	APDX

Public Service Commission of Wisconsin

KAUKAUNA UTILITY

Residential Service – Optional Three-Tier Time of Day

Application: This rate schedule is optional to all Rg-1, Residential Service customers. Customers that wish to be served on this rate schedule must apply to the utility for service. Once an optional customer begins service on this rate schedule, the customer shall remain on the rate for a minimum of one year. Any customer choosing to be served on this rate schedule waives all rights to billing adjustments arising from a claim that the bill for service would be less on another rate schedule than under this rate schedule.

Once on this rate, the utility will review billing annually according to Wis. Admin. Code ch. PSC 113.

Customer Charge:	Single-phase:	$15.00 per month.
	Three-phase:	$25.00 per month.
Energy Charge:	Off-Peak Hours:	$0.0605 per kilowatt-hour (kWh).
	Standard Hours:	$0.1120 per kWh
	On-Peak Hours:	$0.1755 per kWh.

Power Cost Adjustment Clause: Charge per all kWh varies monthly. See schedule PCAC.

Pricing Periods:	Off-Peak Hours:	12:00 a.m. to 5:00 a.m. every day
	On-Peak Hours:	3:00 p.m. to 7:00 p.m. Monday through Friday, excluding holidays specified below.
	Standard Hours:	All times not specified as Off-peak or On-Peak hours.
Holidays:	New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day, or the day designated to be celebrated as such.	

Prompt Payment of Bills: Same as Rg-1.

Minimum Monthly Bill: The minimum monthly bill shall be the customer charge.

Moving Provision: If a customer moves within the utility's service territory, both the original and the new customer have the option to retain time-of-day billing or to transfer to the Residential Service rate, Rg-1, at no cost to the customer.

Joint Residential/Commercial Customers: A customer occupying a building or apartment for residential and commercial purposes jointly shall be billed on another rate which is determined based on the customer's load.

RATE FILE

Sheet No.	1 of 1
Schedule No.	Gs-1
Amendment No.	APDX

Public Service Commission of Wisconsin

KAUKAUNA UTILITY

General Service

Application: This rate will be applied to single and three-phase customers. This includes commercial, institutional, government, farm, and other customers. The monthly Maximum Measured Demand of customers served on this rate shall not exceed 50 kilowatts for three or more months in a consecutive 12-month period.

Gs-1 customers shall be transferred into the appropriate demand class as soon as the application conditions of that class have been met.

Customer Charge: Single-phase: $18.00 per month.
Three-phase: $27.00 per month.

Energy Charge: $0.1177 per kilowatt-hour (kWh).

Power Cost Adjustment Clause: Charge per all kWh varies monthly. See schedule PCAC.

Minimum Monthly Bill: The minimum monthly bill shall be the customer charge.

Prompt Payment of Bills: Same as Rg-1.

Farm Customer: Defined as a person or organization using electric service for the operation of an individual farm, or for residential use in living quarters on the farm occupied by persons principally engaged in the operation of the farm and by their families. A farm is a tract of land used to raise or produce agricultural and dairy products, for raising livestock, poultry, game, fur-bearing animals, or for floriculture, or similar purposes, and embracing not less than 3 acres; or, if small, where the principal income of the operator is derived therefrom. (Otherwise, the service used for residential purposes is classed as residential, and that used for commercial is classed as general service.)

Determination of Maximum Measured Demand: The Maximum Measured Demand in any month shall be that demand in kilowatts necessary to supply the average kilowatt-hours in 15 consecutive minutes of greatest consumption of electricity during each month. Such Maximum Measured Demand shall be determined from readings of permanently installed meters or, at the option of the utility, by any standard methods or meters. Said demand meter shall be reset to zero when the meter is read each month.

RATE FILE

Sheet No.	1 of 2
Schedule No.	Gs-2
Amendment No.	APDX

Public Service Commission of Wisconsin

KAUKAUNA UTILITY

General Service – Optional Time of Day

Application: This rate schedule is optional to all Gs-1, General Service customers. Customers that wish to be served on this rate schedule must apply to the utility for service. Once an optional customer begins service on this rate schedule, the customer shall remain on the rate for a minimum of one year. Any customer choosing to be served on this rate schedule waives all rights to billing adjustments arising from a claim that the bill for service would be less on another rate schedule than under this rate schedule.

Once on this rate, the utility will review billing annually according to Wis. Admin. Code ch. PSC 113.

Gs-2 customers shall be transferred to the appropriate demand class as soon as the application conditions of that class have been met.

Customer Charge: Single-phase: $18.00 per month.
Three-phase: $27.00 per month.

Energy Charge: On-peak: $0.2052 per kilowatt-hour (kWh).
Off-peak: $0.0697 per kWh.

Power Cost Adjustment Clause: Charge per all kWh varies monthly. See schedule PCAC.

Pricing Periods: On-peak: The three on-peak periods available are:
7:00 a.m. to 7:00 p.m. (closed to new customers)
8:00 a.m. to 8:00 p.m.
9:00 a.m. to 9:00 p.m. (closed to new customers)
Monday through Friday, excluding holidays, specified below.

Off-peak: All times not specified as on-peak including all day Saturday and Sunday, and the following holidays: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day, or the day designated to be celebrated as such.

Prompt Payment of Bills: Same as Rg-1.

Minimum Monthly Bill: The minimum monthly bill shall be the customer charge.

Moving Provision: If a customer moves within the utility's service territory, both the original and the new customer have the option to retain time-of-day billing or to transfer to the General Service rate, Gs-1, at no cost to the customer.

General Service – Optional Time of Day

Joint Residential/Commercial Customers: A customer occupying a building or apartment for residential and commercial purposes jointly shall be billed on another rate which is determined based on the customer's load.

RATE FILE

Sheet No. 1 of 2
Schedule No. Cp-1
Amendment No. APDX

Public Service Commission of Wisconsin

KAUKAUNA UTILITY

Small Power Service

Application: This rate will be applied to customers for all types of service if their monthly Maximum Measured Demand is in excess of 50 kilowatts (kW) per month for three or more months in a consecutive 12-month period, but not greater than 200 kW per month for three or more months in a consecutive 12-month period.

Customers billed on this rate shall continue to be billed on this rate until their monthly Maximum Measured Demand is less than 50 kW per month for 12 consecutive months.

Customer Charge: $50.00 per month.

Distribution Demand Charge: $1.50 per kW of distribution demand.

Demand Charge: $9.00 per kW of billed demand.

Energy Charge: $0.0690 per kilowatt-hour (kWh).

Energy Limiter: $0.1303 per kWh
For each month, the customer shall be billed the lesser of 1) the amount for the Energy Limiter or 2) the amount for the Energy Charge plus the amount for the Demand Charge. This provision does not affect the billing of the customer charge, the distribution demand charge, and the PCAC, which are also billed each month.

Power Cost Adjustment Clause: Charge per all kWh varies monthly. See schedule PCAC.

Prompt Payment of Bills: Same as Rg-1.

Minimum Monthly Bill: The minimum monthly bill shall be equal to the customer charge, plus the distribution demand charge.

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Small Power Service

Discounts: The monthly bill for service will be subject to the following discounts applied in the sequence listed below.

Primary Metering Discount: Customers metered on the primary side of the transformer shall be given the following discount on the monthly energy charge, distribution demand charge, and demand charge.

2,300 volts to 15,000 volts inclusive:	2.0 percent
Or:	
Above 15,000 volts:	3.0 percent

The PCAC and the monthly customer charge will not be eligible for the primary metering discount.

Service Voltage Discount: Customers who own and maintain their own transformers or substations shall be given a credit of:

$0.20 per kW of distribution demand if receiving service from 2,300 volts to 15,000 volts, inclusive

Or

$0.40 per kW of distribution demand if receiving service above 15,000 volts

Customer-owned substation equipment shall be operated and maintained by the customer. Support and substation equipment is subject to utility inspection and approval.

Determination of Maximum Measured Demand: The Maximum Measured Demand in any month shall be that demand in kilowatts necessary to supply the average kilowatt-hours in 15 consecutive minutes of greatest consumption of electricity during each month. Such Maximum Measured Demand shall be determined from readings of permanently installed meters or, at the option of the utility, by any standard methods or meters. Said demand meter shall be reset to zero when the meter is read each month.

Determination of Distribution Demand: The Distribution Demand shall be the highest monthly Maximum Measured Demand occurring in the current month or preceding 11-month period.

Determination of Billed Demand: The Billed Demand shall be the Maximum Measured Demand.

Public Service Commission of Wisconsin

KAUKAUNA UTILITY

Small Power Service – Optional Time of Day Service

Application: This rate schedule is optional to all Cp-1 customers. Customers that wish to be served on this rate schedule must apply to the utility for service. Once an optional customer begins service on this rate schedule, the customer shall remain on the rate for a minimum of one year. Any customer choosing to be served on this rate schedule waives all rights to billing adjustments arising from a claim that the bill for service would be less on another rate schedule than under this rate schedule.

Once on this rate, the utility will review billing annually according to Wis. Admin. Code ch. PSC 113.

Customer Charge: $50.00 per month.

Distribution Demand Charge: $1.50 per kW of distribution demand.

Demand Charge: $9.00 per kW of on-peak billed demand.

Energy Charge: On-peak: $0.0838 per kilowatt-hour (kWh).
Off-peak: $0.0611 per kWh.

Power Cost Adjustment Clause: Charge per all kWh varies monthly. See schedule PCAC.

Prompt Payment of Bills: Same as Rg-1.

Minimum Monthly Bill: The minimum monthly bill shall be equal to the customer charge, plus the distribution demand charge.

Pricing Periods: On-peak: 8:00 a.m. to 8:00 p.m., Monday through Friday, excluding holidays, specified below.

Off-peak: All times not specified as on-peak including all day Saturday and Sunday, and the following holidays: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day, or the day designated to be celebrated as such.

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Small Power Service – Optional Time of Day Service

Discounts: The monthly bill for service will be subject to the following discounts applied in the sequence listed below.

Primary Metering Discount: Customers metered on the primary side of the transformer shall be given the following discount on the monthly energy charge, distribution demand charge, and demand charge.

2,300 volts to 15,000 volts inclusive:	2.0 percent
Or:	
Above 15,000 volts:	3.0 percent

The PCAC and the monthly customer charge will not be eligible for the primary metering discount.

Service Voltage Discount: Customers who own and maintain their own transformers or substations shall be given a credit of:

$0.20 per kW of distribution demand if receiving service from 2,300 volts to 15,000 volts, inclusive

Or

$0.40 per kW of distribution demand if receiving service above 15,000 volts

Customer-owned substation equipment shall be operated and maintained by the customer. Support and substation equipment is subject to utility inspection and approval.

Determination of Maximum Measured Demand and On-peak Maximum Demand: The Maximum Measured Demand in any month shall be that demand in kilowatts necessary to supply the average kilowatt-hours in 15 consecutive minutes of greatest consumption of electricity during each month. Such Maximum Measured Demand shall be determined from readings of permanently installed meters or, at the option of the utility, by any standard methods or meters. Said demand meter shall be reset to zero when the meter is read each month. The Maximum Measured Demand that occurs during the On-peak period shall be the On-peak Maximum Demand.

Determination of Distribution Demand: The Distribution Demand shall be the highest monthly Maximum Measured Demand occurring in the current month or preceding 11-month period.

Determination of On-peak Billed Demand: The Maximum Measured Demand that occurs during the On-peak period shall be the On-peak Billed Demand.

Large Power Time of Day Service

Application: This rate will be applied to customers for all types of service, if their monthly Maximum Measured Demand is in excess of 200 kilowatts (kW) per month for three or more months in a consecutive 12-month period, but not greater than 5000 kW per month for three or more months in a consecutive 12-month period.

Customers billed on this rate shall continue to be billed on this rate until their monthly Maximum Measured Demand is less than 200 kW per month for 12 consecutive months.

Customer Charge: $100.00 per month.

Distribution Demand Charge: $2.00 per kW of distribution demand.

Demand Charge: $10.50 per kW of on-peak billed demand.

Energy Charge: On-peak: $0.0700 per kilowatt-hour (kWh).
Off-peak: $0.0513 per kWh.

Power Cost Adjustment Clause: Charge per all kWh varies monthly. See schedule PCAC.

Minimum Monthly Bill: The minimum monthly bill shall be equal to the customer charge, plus the distribution demand charge.

Prompt Payment of Bills: Same as Rg-1.

(Continued on next page)

Large Power Time of Day Service

Pricing Periods:

On-peak: 8:00 a.m. to 8:00 p.m., Monday through Friday, excluding holidays, specified below.

Off-peak: All times not specified as on-peak including all day Saturday and Sunday, and the following holidays: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day, or the day nationally designated to be celebrated as such.

Discounts: The monthly bill for service will be subject to the following discounts applied in the sequence listed below.

Primary Metering Discount: Customers metered on the primary side of the transformer shall be given the following discount on the monthly energy charge, distribution demand charge, and demand charge.

2,300 volts to 15,000 volts inclusive:	2.0 percent
Or:	
Above 15,000 volts:	3.0 percent

The PCAC and the monthly customer charge will not be eligible for the primary metering discount.

Service Voltage Discount: Customers who own and maintain their own transformers or substations shall be given a credit of:

$0.20 per kW of distribution demand if receiving service from 2,300 volts to 15,000 volts, inclusive

Or

$0.40 per kW of distribution demand if receiving service above 15,000 volts

Customer-owned substation equipment shall be operated and maintained by the customer. Support and substation equipment is subject to utility inspection and approval.

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Large Power Time of Day Service

Determination of Maximum Measured Demand and On-peak Maximum Demand: The Maximum Measured Demand in any month shall be that demand in kilowatts necessary to supply the average kilowatt-hours in 15 consecutive minutes of greatest consumption of electricity during each month. Such Maximum Measured Demand shall be determined from readings of permanently installed meters or, at the option of the utility, by any standard methods or meters. Said demand meter shall be reset to zero when the meter is read each month. The Maximum Measured Demand that occurs during the On-peak period shall be the On-peak Maximum Demand.

Determination of Distribution Demand: The Distribution Demand shall be the highest monthly Maximum Measured Demand occurring in the current month or preceding 11-month period.

Determination of On-peak Billed Demand: On-peak Billed Demand shall be the On-peak Maximum Demand.

Industrial Power Time-of-Day Service

Application: This rate will be applied to customers for all types of service if their monthly Maximum Measured Demand is in excess of 5,000 kilowatts (kW) per month for three or more months in a consecutive 12-month period.

Customers billed on this rate shall continue to be billed on this rate until their monthly Maximum Measured Demand is less than 5,000 kW per month for 12 consecutive months.

Customer Charge: $300.00 per month.

Distribution Demand Charge: $1.75 per kW of distribution demand.

Demand Charge:
$17.698 per kW of on-peak billed demand (July & August)
$16.337 per kW of on-peak billed demand (June & September)
$13.202 per kW of on-peak billed demand (All other months)

Energy Charge:
On-peak: $0.0573 per kilowatt-hour (kWh).
Off-peak: $0.0439 per kWh.

Power Cost Adjustment Clause 2: Charge per all kWh and billed demand kW vary monthly. See schedule PCAC2.

Minimum Monthly Bill: The minimum monthly bill shall be equal to the customer charge, plus the distribution demand charge.

Prompt Payment of Bills: Same as Rg-1.

(Continued on next page)

Industrial Power Time-of-Day Service

Pricing Periods:

On-peak: 8:00 a.m. to 8:00 p.m., Monday through Friday, excluding Holidays, specified below.

Off-peak: All times not specified as on-peak including all day Saturday and Sunday, and the following holidays: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day, or the day nationally designated to be celebrated as such.

Discounts: The monthly bill for service will be subject to the following discounts applied in the sequence listed below:

Primary Metering Discount: Customers metered on the primary side of the transformer shall be given the following discount on the monthly energy charge, distribution demand charge, and demand charge.

2,300 volts to 15,000 volts inclusive:	2.0 percent
Or:	
Above 15,000 volts:	3.0 percent

The PCAC and the monthly customer charge will not be eligible for the primary metering discount.

Service Voltage Discount: Customers who own and maintain their own transformers or substations shall be given a credit of:

$0.20 per kW of distribution demand if receiving service from 2,300 volts to 15,000 volts, inclusive

Or

$0.40 per kW of distribution demand if receiving service above 15,000 volts

Customer-owned substation equipment shall be operated and maintained by the customer. Support and substation equipment is subject to utility inspection and approval.

(Continued on next page)

Industrial Power Time-of-Day Service

Determination of Maximum Measured Demand and On-peak Maximum Demand: The Maximum Measured Demand in any month shall be that demand in kilowatts necessary to supply the average kilowatt-hours in 15 consecutive minutes of greatest consumption of electricity during each month. Such Maximum Measured Demand shall be determined from readings of permanently installed meters or, at the option of the utility, by any standard methods or meters. Said demand meter shall be reset to zero when the meter is read each month. The Maximum Measured Demand that occurs during the On-peak period shall be the On-peak Maximum Demand.

Determination of Distribution Demand: The Distribution Demand shall be the highest monthly Maximum Measured Demand occurring in the current month or preceding 11-month period.

Determination of On-peak Billed Demand: On-peak Billed Demand shall be the On-peak Maximum Demand.

Coincident Demand Metering Rider

Application: This rider may be applied to Cp-2 and Cp-3 customers with multiple service entrances on contiguous properties, which are separately metered, whose combined Maximum Coincident Demand is in excess of 200 kilowatts (Cp-2) or 5000 kilowatts (Cp-3) for three or more months in a consecutive 12 month period, and who meet all of the appropriate provisions described below.

Customer Charge: The monthly customer charge shall apply to each separately metered location, as if they were served individually on the Cp-2 and Cp-3 rate schedules.

Determination of Distribution Demand: The Distribution Demand shall equal the sum of the distribution demands of each metered location, as if they were served individually.

Determination of Maximum Measured Demand: The Maximum Measured Demand in any month shall be that demand in kilowatts necessary to supply the average kilowatt-hours in the 15 consecutive minutes of greatest consumption of electricity to a single metered service point during each month. The Maximum Measured Demand shall be determined from individual readings of a permanently installed meter. Said demand meter shall be reset to zero when the meter is read each month.

Determination of Maximum Coincident Demand and Maximum Coincident On-Peak Demand: The Maximum Coincident Demand shall be the greatest single demand which occurs in 15 consecutive minutes during the month resulting from the combination of all separately metered services. The Maximum Coincident Demand that occurs during the On-peak period shall be the Maximum Coincident On-Peak Demand.

Determination of Billed Demand: Same as Cp-2 and Cp-3 with Maximum On-peak Demand replaced with Maximum Coincident On-Peak Demand.

Determination of Energy Charge: Same as Cp-2 and Cp-3.

Determination of Minimum Monthly Bill: Same as Cp-2 and Cp-3.

General Provisions:

1. The determination of customer class for billing purposes shall be based on the maximum coincident demand.

2. Customers selecting service under this rider shall make a one-time, nonrefundable payment of $100 at the time service is initiated.

3. Customers selecting service under this rider may terminate it by providing 30 days' written notice to the utility. The utility shall notify the customer that they are responsible for any increases in bills that may result by eliminating coincident billing.

Coincident Demand Metering Rider

4. Primary metered services may only be combined with other primary metered services for the purposes of coincident billing.

5. Customers with multiple service entrances may be served under this rider only if all metering points that can be combined are combined together for coincident billing.

6. The utility shall annually notify all customers served on the Cp-2 and Cp-3 rate schedule that coincident billing is available upon request.

RATE FILE

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Public Service Commission of Wisconsin

KAUKAUNA UTILITY

Street and Security Lighting Service

Application: This schedule will be applied to lighting service.

This rate schedule is closed to new mercury vapor lights.

Investment charge:

Overhead:	
25-75 W LED	$9.50 per lamp per month
76-150 W LED	$10.25 per lamp per month
150 W LED	$13.00 per lamp per month
100 W HPS	$9.50 per lamp per month
250 W HPS	$10.25 per lamp per month
400 W HPS	$12.00 per lamp per month
400 W HPS Wide Light	$12.50 per lamp per month
Ornamental:	
25-75 W LED	$15.00 per lamp per month
76-150 W LED	$15.50 per lamp per month
150 W LED	$16.00 per lamp per month
100 W HPS	$13.50 per lamp per month
150 W HPS	$14.00 per lamp per month
250 W HPS	$14.50 per lamp per month
400 W HPS	$15.00 per lamp per month
Security:	
25-75 W LED	$10.00 per lamp per month
76-150 W LED	$11.00 per lamp per month
150 W LED	$12.50 per lamp per month
100 W HPS	$10.50 per lamp per month
100 W HPS Ornamental	$14.00 per lamp per month
250 W HPS	$11.00 per lamp per month
400 W HPS	$12.00 per lamp per month
400 W HPS Wide Light	$13.00 per lamp per month
400 W HPS Ornamental	$16.25 per lamp per month

Energy Charge: $0.0804 per kilowatt-hour (kWh).

Power Cost Adjustment Clause: Charge per all kWh varies monthly. See schedule PCAC.

Street and Security Lighting Service

Prompt Payment of Bills: Same as Rg-1.

Note:
LED = Light Emitting Diode
LED = Light Emitting Diode

RATE FILE

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Public Service Commission of Wisconsin

KAUKAUNA UTILITY

Other Charges and Billing Provisions

Budget Payment Plan: A budget payment plan, which is in accordance with Wis. Admin. Code ch. PSC 113, is available from the utility. The utility does not use a fixed budget year. The utility will calculate the monthly budgeted amount by spreading the estimated annual bill over eleven months, with the last month consisting of any end of year adjustments.

Reconnection Billing: All customers whose service is disconnected in accordance with the disconnection rules as outlined in Wis. Admin. Code ch. PSC 113, shall be required to pay a reconnection charge. The charge shall be **$45.00** during regular office hours. After regular office hours the minimum reconnection charge of **$45.00** applies plus any overtime labor costs, not to exceed a total maximum charge of **$80.00**.

Reconnection of a Seasonal Customer's Service: Reconnection of a service for a seasonal customer who has been disconnected for less than one year shall be subject to the same reconnection charges outlined above. A seasonal customer shall also be charged for all minimum bills that would have been incurred had the customer not temporarily disconnected service.

Payment Not Honored by Financial Institution Charge: The utility shall assess a **$17.00** charge when a payment rendered for utility service is not honored by the customer's financial institution. This charge may not be in addition to, but may be inclusive of, the water utility's insufficient fund charge when the check was for payment of both electric and water service.

Average Depreciated Embedded Cost: The embedded cost of the distribution system (excluding the standard transformer and service facilities), for each customer classification, is determined based on methodology authorized by the Public Service Commission of Wisconsin, and described in the utility's Electric Rules. The average depreciated embedded cost by customer classification is as follows:

Residential Service: **$607.58**.

Apartment and Rental Units Separately Metered: **$607.58** per unit metered.

Subdividers and Residential Developers: **$607.58** per unit.

General Service: (Including Multi-Unit Dwellings If Billed on One Meter): **$1396.49**.

Power Service: $171.35 per kW (Cp-1), $89.41 per kW (Cp-2), $71.89 per kW (Cp-3), of average billed demand

Street Lighting: **$17.38**.

Standby, Maintenance, and Displacement Power Rider

Application:
This Standby, Maintenance, and Displacement Power ("Standby Services") Rider is available to any eligible retail customer of the utility. An eligible retail customer is one that:

a. Owns a single generating unit ("Generator") located in the customer's premises within the utility's service territory having a capacity of at least 15,000 kW, but not more than 60,000 kW;
b. Operates such Generator in parallel with the utility's electric system, and uses that Generator to regularly supply all or part of its own electric load requirements (an electric generator operated primarily for emergency purposes, as determined by the utility, is not eligible for Standby Services);
c. Meters the electricity produced by the Generator directly, recording 15 minute interval data; and,
d. Executes a written contract (the "Standby Services Agreement") with the utility in accordance with the provisions of this rider.

Application of Wholesale and Retail Tariffs: The combination of this Standby Services Rider and the corresponding wholesale Standby Services schedule shall result in the purchase of Standby Services by the utility from its wholesale supplier, WPPI Energy ("WPPI"), and the resale of such Standby Services by the utility to its eligible retail customer(s). The capacity associated with any Standby Services purchased under this schedule shall be subtracted from the eligible customer's total metered demand when determining the eligible customer's On-peak Maximum Demand under the utility's applicable retail rate schedule (e.g., Cp-3). No adjustment shall be made to the determination of Distribution Demand. Any energy supplied in connection with Standby Services will be supplied and priced as energy under the utility's retail rate schedule applicable to the eligible customer. There will be no adjustment for losses.

Annual Nomination: On or before each October 25, unless the utility grants an extension, the eligible customer shall inform the utility or its designee of the Standby Power amount it reserves for the twelve month period beginning the following June 1 (the "Annual Nomination"). The Annual Nomination shall be documented in the Standby Services Agreement. The Annual Nomination shall be a multiple of 1,000 kilowatts (kW) and not exceed the lesser of:

a. the Generator capacity, or
b. the expected peak demand of the customer's electric requirements for that period, as determined by the customer

Available Standby Services: The following are available as Standby Services.

Standby Power: Utility will supply Standby Power to the customer, in an amount up to the customer's Annual Nomination, to serve the customer's load during unscheduled outages of the

Standby, Maintenance, and Displacement Power Rider

Generator. Such Standby Power will be provided on a best efforts basis, but utility may restrict it if system conditions warrant.

Maintenance Power: Utility will supply Maintenance Power to serve the eligible customer's load during properly scheduled outages of the Generator, if the customer has reserved Standby Power. Maintenance Power is temporary service, available up to the Annual Nomination. Maintenance Power is not available between June 1 and September 30 and is limited to 30 On-Peak Period days, as defined in the WPPI Schedule for Firm Requirements Service ("WPPI Firm Rate") per year. A customer properly schedules Maintenance Power by notifying the utility or its designee no less than 90 days prior to Generator maintenance. A customer may request maintenance upon shorter notice, but the utility or its designee may decline such request in its discretion. A maintenance period begins when customer starts taking the Generator out of service and ends when it is again capable of full performance. By providing no less than 30 days' notice to the eligible customer (or less in the event of a system emergency), the utility or its designee may require a generator larger than 25,000 kW to defer planned maintenance until an alternative time identified by the utility or its designee and agreeable to the customer.

Displacement Power: Utility or its designee may from time-to-time offer Displacement Power to the customer during specific hours when utility or its wholesale supplier has surplus energy available. Displacement Power is temporary curtailable service, available up to an amount specified by the utility or its designee at the time. Neither the utility nor its designee shall have any obligation to offer Displacement Power and the customer has no obligation to accept Displacement Power. If utility or its designee notifies customer that Displacement Power will be available during specified hours in the future ("Available Displacement Hours" or "ADH"), the customer may elect to displace Generator output with Displacement Power during ADH. In such event, the customer shall notify utility or its designee of its election no later than the time specified in the Standby Services Agreement. Utility or its designee may curtail Displacement Power if system conditions warrant.

Rates for Standby Services: The following monthly charges shall apply for Standby Services.

Administrative Charge: $300.00 per month

Demand Charge:
Standby Power Demand Charge = WDC x **Peak Use** x **(Hours Used**/120) x **DLF** subject to the Minimum Standby Power Demand Charge and the Maximum Standby Power Demand Charge specified below.

Where:

"**WDC**" is the wholesale Demand Charge specified in the WPPI Firm Rate (specified in $ per kW of Billed Demand per month, varying by season, and as adjusted monthly in accordance with the Demand Charge Adjustments, DCA1 and DCA2).

Standby, Maintenance, and Displacement Power Rider

"**Peak Use**" is the maximum amount of Standby Power used in any billing interval during the On-Peak Period of the applicable month (specified in kW).

"**Hours Used**" is the number of hours that Standby Power was used during the On-Peak Period of the applicable month (specified in hours).

"**DLF**" is the distribution loss factor shown in the following table.

Interconnection Voltage of the Customer	DLF
100 kV or higher	1.00
12 kV or higher, but less than 100 kV	1.02
Less than 12 kV	1.03

Minimum Standby Power Demand Charge: The above formula notwithstanding, in no case shall the monthly Standby Power Demand Charge be less than:

WDC x Annual Nomination x .127

Maximum Standby Power Demand Charge: If, in any month, the above formula yields a Standby Power Demand Charge that is greater than the Minimum Standby Power Demand Charge, the Standby Power Demand Charge shall further be limited to not exceed:

WDC x Annual Nomination

There is no demand charge for Maintenance Power or for Displacement Power.

Transmission Charge:
Transmission Charge = WTC x SPCTP, where**:**

"**WTC**" is the Transmission Demand Charge specified in the WPPI Firm Rate (specified in $ per kW of Billed Demand)

"**SPCTP**" is the sum of the Standby Power and the Maintenance Power (specified in kW) provided by the utility to the eligible customer during that hour of the month in which the applicable transmission provider (e.g., American Transmission Company) peaks.

There is no Transmission Charge for Displacement Power.

Standby, Maintenance, and Displacement Power Rider

Energy Charge:

Energy Charge is the Energy Charge specified in the utility's retail rate schedule applicable to the eligible customer (e.g., Cp-3) (specified in $ per kWh) multiplied by the sum of all energy supplied in connection with Standby Power, Maintenance Power, and Displacement Power (specified in kWh), adjusted monthly in accordance with the Power Cost Adjustment Clause specified in that retail rate schedule.

Terms and Conditions:

a. Each eligible customer will remain on the utility's Standby Services tariff for a period of not less than one complete year running June 1 to May 31 ("Contract Year"). Such service shall continue on a year to year basis, terminable by either party upon notice given on or before October 25 of the Contract Year.
b. Utility and each eligible customer shall enter into an agreement for the Standby Services provided by utility.
c. Customer shall notify utility or its designee immediately if it requires Standby Power and the expected duration associated with the need for standby power in accordance with the procedure detailed in the Standby Services Agreement.
d. Utility, at its discretion, may require that the eligible customer allow WPPI-owned metering to be installed on site to monitor eligible customer's generating unit.
e. Customers will be billed under the applicable rate schedule for all service provided for the benefit of eligible customers and not billed under this Rider.
f. Utility will not be liable for any damages sustained by the eligible customer because of interruptions, deficiencies or imperfections of electric service provided under this Rider.
g. Utility's obligations under this Rider are subject to the continued availability of a wholesale Standby Services schedule from WPPI.

New Load Market Pricing Service

1. Effective In

All territories served by the Utility.

2. Eligibility

Available to existing and new customers that would not expand load or take service from the Utility absent this New Load Market Pricing (NLMP) Service to include: (A) any existing customer with a Maximum Measured Demand in excess of 200 kW for 3 or more months in a consecutive 12 month period and an expected electric demand growth of at least 400kW or (B) a new customer with an expected peak demand of at least 400 kW.

An existing customer shall state that this NLMP Service was a factor in its decision to expand load with the Utility, and a new customer shall state that this NLMP Service was a factor in its decision to take service with the Utility.

This NLMP Service is only available to customers that (A) have informed the Utility at least 3 months prior to receiving service., (B) have electric meters that record 15 minute interval load data prior to the commencement of service hereunder, (C) will be billed on a calendar month basis, (D) have completed an application for participation under the NLMP Service and received approval from the Utility (an "Approved Application") and (E) have had an energy efficiency assessment completed by a Focus on Energy Advisor within 12 months prior to taking service or agree to have an energy efficiency assessment completed by a Focus on Energy Advisor within six months after taking service.

A customer under this NLMP Service shall maintain a minimum of 400 kW of incremental demand for eight out of the twelve months in each year of the contract. Failure to meet this criterion will result in the customer being removed from this service. For purposes of eligibility, incremental demand is:

- For an existing customer that is expanding, the customer's total demand purchased from the Utility minus the Demand Baseline Levels defined below.
- For a new customer, the customer's total demand purchased from the Utility for the applicable month.

This NLMP Service is not available to customers transferring existing load from any other electric utility provider in Wisconsin to the Utility.

This NLMP Service is available to eligible customers on a first-come, first-served basis up to a maximum eligible load of 10 MW per customer, provided that (A) there is sufficient unsubscribed capacity available to the Utility under the WPPI Wholesale Sale of Electricity Requirements for Eligible Load Growth wholesale schedule (the "WPPI NLMP Schedule"), and (B) WPPI Energy,

New Load Market Pricing Service

the Utility's wholesale electricity supplier ("WPPI"), approves such service on a first-come, first-served basis. Service under the NLMP must commence no later than 3 months after the date the Approved Application is signed by the customer and the Utility.

3. Term

Service under the NLMP is for a single term of four (4) consecutive years from the commencement of service on the first day of the month specified in an Approved Application. A customer may terminate service on the annual anniversary date of the NLMP Service as long as the customer provides at least 30 days' written notice to the Utility. Upon termination, the customer will return to service under an applicable rate for which it is eligible under the utility's service. A customer who terminates service or is removed may not return to the NLMP Service.

4. Rate

The eligible electric consumption for this NLMP Service is the amount of customer electric consumption above the customer's Monthly Baseline Demand Level and Monthly Baseline Energy Levels (defined below). The standard applicable retail service rates shall apply for customer electric consumption up to and including its Baseline Demand Level and Baseline Energy Levels and amounts above the Baseline Demand Level and Baseline Energy Levels will be subject to the charges and rates defined below.

A. **Administrative Charge**: $150.00 per month

B. **Incremental Demand Rate**:
If the customer's monthly peak demand exceeds the Baseline Demand Level for the month, utility will charge the customer for the monthly peak demand less the Baseline Level (i.e., the "Incremental Demand") at the following monthly fixed costs charged to the Utility by WPPI to provide service to the customer under the NLMP Service. These costs are a pass through of charges from the Midcontinent Independent System Operator, Inc. ("MISO") and generally include, but are not limited to the following:

1. MISO Resource Adequacy charge based on the applicable MISO LRZ clearing price and accounting for MISO's reserve margin requirement [applies only to firm load];
2. MISO Network Integration Transmission Service charge (actual previous year average per unit cost incurred by WPPI load); per kW of Incremental Demand
3. Other fixed transmission and ancillary service costs
    a. MISO Schedule 1: Scheduling, System Control & Dispatch;
    b. MISO Schedule 2: Reactive Supply & Voltage Control;
    c. MISO Schedule 10: MISO Cost Adder;
    d. MISO Schedule 10-FERC: FERC Annual Charges;
    e. MISO Schedule 11: Wholesale Distribution Service;

f. MISO Schedule 26: Network Upgrade Transmission Expansion Charge;
g. MISO Schedule 33: Blackstart Service;
h. MISO Schedule 43: System Support Resources; and
i. Direct Network Upgrade Charges (if any)

A multiplication factor to account for distribution loss and applicable gross receipts taxes will be applied to the Incremental Demand Rate calculated from the above components as further described below. In addition, a 1.02 multiplication factor will be applied to the Incremental Demand Rate calculated from the above components to account for transmission losses.

The MISO Resource Adequacy charge will only apply to firm load, and customers taking service on an interruptible basis will not incur that component of the Incremental Rate.

C. **Incremental Energy Rate:**

If the customer's energy consumption exceeds the Monthly Baseline Energy Level (on-peak or off-peak, as applicable) in any hour of the billing month, the Utility will charge the customer for the hourly energy consumption less the Monthly Baseline Energy Level (i.e., the "Incremental Hourly Energy") at the following energy costs charged to the Utility by WPPI to provide service to the customer under the NLMP Service. Except for the margin on energy, these costs are a pass through of charges from MISO and generally include, but are not limited to the following:

1. MISO Energy Costs:
    a. Day-Ahead Hourly Locational Marginal Price (LMP) at applicable MISO CPNode per kWh of Incremental Hourly Energy (currently "WEC.WPPI" for the Utility)
    b. Day-Ahead RSG Distribution Amount
    c. Real-Time Demand Response Uplift Charge
    d. Real-Time Distribution of Losses Credit
    e. Real-Time MVP Distribution Amount
    f. Real-Time Neutrality Uplift Amount
    g. Real-Time RSG First Pass Distribution Amount
2. MISO Market Administration:
    a. Schedule 17: Day-Ahead and Real-Time Market Administration Amount
    b. Schedule 24: Control Area Operator Cost Recovery
3. MISO Ancillary Services:
    a. Schedule 3: Regulation Cost Distribution Amount
    b. Schedule 5: Spinning Reserve Cost Distribution Amount
    c. Schedule 6: Supplemental Reserve Cost Distribution Amount
4. MISO Transmission:
    a. Schedule 10: MISO Cost Adder

b. Schedule 26: Multi-Value Project Cost Recovery

5. Adder on Energy at $0.0005/kWh

A multiplication factor to account for distribution loss and applicable gross receipts taxes will be applied to the Incremental Energy Rate calculated from the above components as further described below.

The minimum Incremental Energy Rate billed shall not be less than $0.007 / kWh in any hour.

D. **Incremental Distribution Demand Rate:**

A distribution demand billing option will be selected by the customer for the contract term as the Incremental Distribution Demand Rate for demand above the Baseline Distribution Demand Level (defined below) as follows:

1. Option 1 – Distribution Demand above the Baseline Distribution Demand Level will be subject to the same Distribution Demand charges applied to demand up to the Baseline Distribution Demand Level. A customer that selects Option 1 will receive a construction allowance per the Utility's Electric Rules.

2. Option 2 – Distribution Demand above Baseline Distribution Demand Level will not be subject to the Distribution Demand charges applied to demand up to the Baseline Distribution Demand Level. A customer that selects this Option 2 will not receive a construction allowance per the Utility's Electric Rules.

5. Monthly Baseline Demand Levels and Monthly Baseline Energy Levels for Existing Customers

Each existing customer's Monthly Baseline Demand Level and Monthly Baseline Energy Levels shall be based on the most recent available historical 12 consecutive month time period (i.e., the "Baseline Period") preceding the date of an Approved Application. Historical electric consumption patterns and demand levels experienced during the Baseline Period make up Monthly Baseline Demand Levels and Monthly Baseline Energy Levels that are to be used for billing for the duration of the applicable term of the NLMP Service. These levels are to be determined prior to beginning service and will remain constant throughout the term of service.

Specifically, baseline levels will be established for monthly demand and monthly on- and off-peak energy as each of the following:

- Average hourly on-peak energy consumption by month for each of the twelve months preceding an Approved Application ("Monthly On-Peak Baseline Energy Level");
- Average hourly off-peak energy consumption by month for each of the twelve months preceding an Approved Application ("Monthly Off-Peak Baseline Energy Level");

- Firm on-peak demand by month for each of the twelve months preceding an Approved Application ("Monthly Baseline Demand Level"); and

The baseline 12-month ratcheted customer demand (the "Baseline Distribution Demand") will remain the same over the entire term of NLMP service and will be equal to the Distribution Demand applicable in the month immediately preceding the date of an Approved Application.

Adjustments to the historical consumption patterns may be made by the Utility to eliminate data anomalies in the Baseline Period that are not expected to reoccur, or to accommodate unique production patterns as demonstrated in the historical data from the 24 months preceding the date of an Approved Application (e.g. if production is commonly reduced during a specific day of the week for maintenance shutdown).

6. Baseline Demand Levels and Baseline Energy Levels for New Customers

Baseline Demand Levels and Baseline Energy Levels for new customer accounts with less than 12 months of history will be based on a forecast, supplied by the new customer and reasonable to the Utility, of electric energy consumption and demand for the new facility. If applicable, the new customer must demonstrate how the new facility differs from prior facilities served by the Utility such that consumption patterns or levels at the new facility are dissimilar to that of past facilities. Corporate name changes, change in ownership of a facility or a corporation, the formation of subsidiaries, or similar actions will not qualify a customer as a new customer for purposes of determining the Baseline Demand Levels and Baseline Energy Levels.

Baseline Demand Levels and Baseline Energy Levels for new customers require approval by the Utility and will be no less than 70 percent of the forecasted demand and energy consumption for year one of service under this NLMP Service. After year one, the original Baseline Levels will be adjusted to new Baseline Levels for the remainder of the contract term to reflect the percentage of actual electric consumption in year one, rather than the percentage of the original forecast of year one consumption. For example, if the initial Baseline Level agreed upon for a specific month was at 70 percent of the year one energy forecast and that forecast was 1,000 MWh, then the initial Baseline would reflect 700 MWh. If actual consumption in that month of year one turned out to be 1,100 MWh, the Baseline would then be adjusted for that month in the remaining years of the contract term to reflect 70 percent of 1,100 MWh, which equates to 770 MWh.

The Baseline Distribution Demand will be equal to zero for the entire term of NLMP service.

7. Energy Reductions Measures and Baseline Levels

For existing customers and new customers in the second and subsequent years of service under this schedule, the Baseline may be adjusted to reflect a systematic and permanent change in Customer production levels as a result of the implementation of energy efficiency, conservation,

and process improvement measures, or through the installation of new equipment as these measures relate to the Baseline. The Customer must request a review of their historical Baseline period and provide the Utility with supporting documentation, which in the judgement of the Utility, after its review and verification indicates that the reduction is permanent and due to the aforementioned measures. This adjustment will not take effect until the beginning of the billing period following the execution of an amended contract. Baseline adjustments upon Customer request and pursuant to this condition will not occur more than once in a 12-month period.

8. Distribution Loss Multiplication Factor

The following table defines the Distribution Loss Multiplication Factor for customers under this NLMP Service:

	Multiplication Factor
Interconnection Voltage Greater than or equal to 100 kV	1.00
Interconnection Voltage Greater than 12 kV and Less than 100 kV	1.02
Interconnection Voltage Less than 12 kV	1.03

9. Gross Receipts Taxes Multiplication Factor

A Gross Receipts Taxes Multiplication Factor of 1.0319 times the total bill shall apply to applicable customer load served under this NLMP Service and located outside the municipal boundaries of the Utility.

Parallel Generation (20 kW or less) -- Net Energy Billing

1. Effective In

   All territories served by the utility.

2. Availability

   Available for single-phase and three-phase customers where a part or all of the electrical requirements of the customer are supplied by the customer's generating facilities, where such facilities have a total generating capability of 20 kW or less, where such facilities are connected in parallel with the utility and where such facilities are approved by the utility.

3. Rate

   The customer shall be billed monthly on a net energy basis and shall pay the fixed charge and energy charge specified in the rate schedule under which he is served.
   If, in any month, the customer's bill has a credit balance of $25 or less, the amount shall be credited to subsequent bills until a debit balance is reestablished. If the credit balance is more than $25, the utility shall reimburse the customer by check upon request. Monthly credits shall be computed by taking the net excess kilowatt-hours produced times the sum of the applicable energy charge plus monthly power cost adjustment clause (PCAC).

4. Metering and Services Facilities

   A customer who is served under a regular rate schedule shall have any ratchet and/or other device removed from his meter to allow reverse power flow and measurement of net energy used. Customers eligible for net energy billing but with existing metering facilities equipped with ratchets or other devices preventing reverse registration (i.e. time-of-use metering facilities) may request that the utility install the necessary metering to permit such billing.

5. Customer Obligation

   See Wis. Admin. Code ch. PSC 119.

Customer-Owned Generation Systems (Greater than 20 kW)

Effective In

All territories served by the utility

2. Availability

Available for single-phase and three-phase customers where a part or all of the electrical requirements of the customer are supplied by the customer's generating facilities, where such facilities have a total generating capability of greater than 20 kW, where such facilities are connected in parallel with the utility. Customers not desiring to sell energy under this rate have the right to negotiate a buy-back rate.

The energy rate indicated below is the minimum for electrical energy. Should the utility be unwilling to pay the minimum rate for electrical energy, the utility shall agree to transport such electrical energy to another utility that will pay such minimum rate. The utility shall recover actual costs of such transportation from the generating customer.

3. Rate

Customers shall receive monthly payments for all electricity delivered to the utility and shall be billed by the utility for metering and associated billing expenses specified in the latest rates of the wholesale supplier unless the latest rates of the wholesale supplier do not properly reflect avoided costs. In such event, the Commission, upon request, may determine appropriate rates. The utility shall have on file a copy of the latest customer-owned generation system rates for its wholesale supplier.

On-Peak and Off-Peak Hours and Holidays

On-peak and off-peak hours and holidays are those specified in the wholesale suppliers latest rates.

5. Minimum Charge

The monthly minimum charge paid by the customer shall be the customer charge.

6. Power Factor

The customer shall operate on a net power factor of not less than 90 percent.

Customer-Owned Generation Systems (Greater than 20 kW)

7. Negotiated Rates

Customers with generation systems greater than 20 kW have the right to negotiate a buy-back rate. The buy-back rate cannot be less than the full avoided cost.

The following are the required procedure guidelines:

a. The utility must respond to the customer-owned generating system within 30 days of the initial written receipt of the customer-owned generating system proposal and within 30 days of receipt of a subsequent customer-owned generating system proposal,

b. The utility's rejection of the customer-owned generating system proposal must be accompanied by a counter-offer relating to the specific subject matter of the customer-owned generating system proposal, and

c. If the utility is unable to respond to the customer-owned generating system proposal within 30 days it shall inform the customer-owned generating system of:

   1) Specific information needed to evaluate the customer-owned generating system proposal.

   2) The precise difficulty encountered in evaluating the customer-owned generating system proposal.

   3) The estimated date that it will respond to the customer-owned generating system proposal.

d. The Commission may become involved in the utility negotiations upon showing by either utility or the customer-owned generating system that a reasonable conclusion cannot be reached under the above guidelines. The Commission may provide a waiver to the guidelines and order new negotiation requirements so that a reasonable conclusion can be reached.

e. A copy of all negotiated buy-back rates shall be sent to the Commission. These rates shall not be effective until the contract is placed on file at the Commission.

8. Charges for Energy Supplied by the Utility

Energy supplied by the utility to the customer shall be billed in accordance with the standard applicable rate schedules of the utility.

Customer-Owned Generation Systems (Greater than 20 kW)

9. Maintenance Rate

A customer-owned generation facility may be billed lower demand charges for energy purchased during scheduled maintenance provided written approval is obtained in advance from the utility. Demand charges other than "Customer Demand" shall be prorated if maintenance is scheduled such that the utility does not incur additional capacity costs. Said probation shall be the demand charge times the number of authorized days of scheduled maintenance divided by the number of days in the billing period.

10. Application Process and Customer Obligation

See Wis. Admin. Code ch. PSC 119, Rule for Interconnecting Distributed Generation Facilities.

11. Utility Obligation

a. Metering Facilities

The utility shall install appropriate metering facilities to record all flows of energy necessary to bill in accordance with the charges and credits of the rate schedule.

b. Notice to Communication Firms

Each electric utility shall notify telephone utility and cable television firms in the area when it knows that customer-owned generating facility is to be interconnected with its system. This notification shall be as early as practicable to permit coordinated analysis and testing in advance of interconnection, if considered necessary by the electric or telephone utility or cable television firm.

12. Right to Appeal

The owner of the generating facility interconnected or proposed to be interconnected with a utility system may appeal to the Commission should any requirement of the utility service rules filed in accordance with the provisions of Wis. Admin. Code § PSC 119.40, or the required contract be considered to be excessive or unreasonable. Such appeal will be reviewed and the customer notified of the Commission's determination.

Solar Renewable Energy Distributed Generation (Limited Participation)

This rate schedule is closed to any new customers

Effective In
All territories served by the utility.

Availability

Available to customers who own small solar photovoltaic (PV) electric generating facilities that are approved by the Utility. Individual project nameplate rated capacity is limited to a maximum of 6 kW dc or the total PV generation nameplate capacity allowable under this tariff, whichever is less. Under this tariff, the total PV generation nameplate capacity for all the Utility's participating customers shall be limited to a maximum capacity of 24 kW dc or, provided that there is sufficient unsubscribed PV capacity available under WPPI Energy's Schedule for Purchase of Solar Photovoltaic Energy, the Utility's total PV generation nameplate capacity may be increased by an amount not to exceed 72 kW dc.

Rates:

1. Metering Charge: **$1.00** per month. This is in addition to any customer charge applicable under the retail tariff the customer is currently receiving service under. A separate meter is required to measure the electricity produced by the customer.

2. Energy Purchase Rate: The Utility will purchase 100% of the generator output from the customer. The Utility will then resell the PV energy to WPPI Energy. The PV generator's output shall be measured separately from the customer's usage. The energy buy-back rate provided under this tariff shall be equal to WPPI Energy's wholesale PV energy buy-back rate as specified in WPPI Energy's Schedule for Purchase of Solar Photovoltaic Energy in effect at the time the customer enters into a buy-back contract with the Utility. The customer will receive a monthly credit on their electric utility bill for the energy sold to the Utility at the above rate. The Utility shall maintain copies of each revision of WPPI Energy's Schedule for Purchase of Solar Photovoltaic Energy with the Utility's authorized tariffs.

Customer Obligation:
See Wis. Admin. Code ch. PSC 119

Utility Obligations:

1. Metering Facilities: The Utility shall install appropriate metering facilities to record all flows of energy necessary to bill in accordance with the charges and credits of the rate schedule.

Solar Renewable Energy Distributed Generation (Limited Participation)

2. Notice to Communication Firms: The Utility shall notify telephone utility and cable television firms in the area when it knows that a customer-owned generating facility will be interconnected with its system. This notification shall be as early as practicable to permit coordinated analysis and testing in advance of interconnection if considered necessary by the electric or telephone utility or cable television firm.

Terms and Conditions:

1. Contract Requirement: A ten (10) year contract is required between the Utility and the participating customer. The contract shall specify the energy buy back rate and any safety, system protection, and power quality terms or rules with which the generator(s) must comply. WPPI Energy shall obtain full rights to and own all Renewable Energy Credits and Attributes generated by the project(s).

2. Interconnection Requirements: Generation facilities must meet the interconnection requirements of the "Rules for Interconnecting Distributed Generation Facilities" (Wis. Admin. Code ch. PSC 119). Interconnection of the generator will be at service voltage only.

3. Distribution Outages: Under certain conditions, the distribution system may experience a short term failure and may not be able to accept output from PV generators. These events occur periodically and there will be no compensation to the customer, by the Utility or WPPI Energy, for energy that cannot be delivered to the utility during distribution outages.

Shared Savings (Limited Participation)

Purpose and Availability

Available to customers served under Rate Schedules Gs-1, Gs-2, Cp-1, Cp-1 TOD, Cp-2 and Cp-3 who implement eligible energy efficiency projects, meet applicable credit requirements and enter into a Shared Savings agreement with the utility. The principal focus of the program is eligible projects where advance utility payment for energy cost savings to the customer is $50,000 or less. In limited circumstances, and on a case-by-case basis, the utility may at its discretion make advance payments of up to $500,000 for eligible customer expansion projects or new customer projects.

Application

Under this program, the utility will contribute an advance payment for energy cost savings related to energy efficiency projects to eligible retail customers. The amount of the advance payment will be based on energy savings achieved over a 60 month period, capped at the lesser of the project cost or the maximum advance payment per customer identified as follows:

1. For projects other than new customers or expansion projects noted below, the maximum advance payment for energy cost savings is $50,000 per customer.

2. For new customers or existing customers that are expanding where the new customer's load or the existing customer's expansion is expected to be greater than or equal to 200 kW, the maximum advance payment for energy cost savings is $500,000 per customer.

WPPI Energy capital will be used to underwrite this program and advance payments for energy cost savings are subject to the availability of WPPI Energy capital allotted to this program.

The customer will repay the advance payment in installments on the customer's retail electric bill over a term of up to 60 months at a 2% annual interest rate. WPPI Energy will recover the same installments from the utility on its wholesale power bill.

Terms and Conditions

1. Customer must complete a Shared Savings application which is subject to the approval of the utility and WPPI Energy.

2. Customer must pass a credit review.

3. Customer must enter into a contract with the utility.

4. Projects must reduce electric use and/or demand for the duration of the repayment period.

Shared Savings (Limited Participation)

5. Projects must meet all minimum efficiency requirements. Minimum efficiency requirements will be aligned with those set forth by the Wisconsin Focus on Energy program.

6. The customer applying must agree with all Shared Savings requirements relevant to the installation of the project equipment, including the right of the utility to have the equipment removed at the expense of the customer in the event of default.

7. Upon completion, the customer will submit a Certificate of Project Completion form to the utility.

RATE FILE

Sheet No.	1 of 1
Schedule No.	CTC-1
Amendment No.	APDX

Public Service Commission of Wisconsin

KAUKAUNA UTILITY

Commitment to Community Program Rider

Under provisions of 1999 Wisconsin Act 9 and 2005 Wisconsin Act 141, a municipal electric utility shall charge each customer a low-income assistance and energy efficiency fee. Fifty percent of the fees charged by the municipal utility shall be used for low-income assistance programs and the remainder will be used for energy efficiency programs. Low-income programs may include assistance to lowincome households for weatherization and other energy conservation services, payment of energy bills or early identification or prevention of energy crises. Energy efficiency programs may include those programs designed to reduce the demand for natural gas or electricity or improving the efficiency of its use during any period.

Pursuant to Wis. Stats. §§ 16.957(5) and 196.374(7), each municipal electric utility must collect an average of $16 per meter per year. The actual amount of fees paid by a customer cannot exceed the lesser of 3 percent of all other billed electric charges or $750 per month. These fees are not subject to Gross Receipts or Sales Taxes. A municipal utility may determine the amount that a particular class of customers is required to pay and may charge different fees to different classes of customers.

Kaukauna Utilities, in compliance with these laws and, as of the "Effective Date" established below, has set the fees for each retail electric customer rate classification as follows:

Residential Service (Rg-1, Rg-2, Rg-3)	3.00% of the total electric bill not to exceed $1.12
General Service (Gs-1, Gs-2)	3.00% of the total electric bill not to exceed $2.32
Small Power Service (Cp-1, Cp-1 TOD)	3.00% of the total electric bill not to exceed $7.50
Large Power TOD Service (Cp-2)	3.00% of the total electric bill not to exceed $35.00
Industrial Power TOD Service (Cp-3)	3.00% of the total electric bill not to exceed $50.00
Street and Security Lighting Service (Ms-1)	3.00% of the total electric bill not to exceed $1.12

Questions regarding low-income assistance and energy efficiency fees or Kaukauna Utilities' Commitment to Community Programs should be directed to Kaukauna Utilities at (920) 766-5721.

RATE FILE

Sheet No.	1 of 1
Schedule No.	RER-1
Amendment No.	APDX

Public Service Commission of Wisconsin

KAUKAUNA UTILITY

Renewable Energy Rider

Availability: Service under this rider is available to all customers currently served under all rate schedules. This rider allows customers the option of purchasing blocks of their energy from renewable resources.

Application: Renewable energy will be sold only in blocks of 300 kWh per month. Customers choosing to be served under this rider will pay the Block Charge for Renewable Energy in addition to the regular monthly charges, including the Power Cost Adjustment Clause, under their current applicable rate schedules. All of the provisions of the current applicable rate will apply to the customer's total usage. The charge for renewable energy will be as stated below:

Block Charge for Renewable Energy: $2.00 per 300 kWh block of renewable energy per month for less than 20 blocks per month. $1.00 per 300 kWh block of renewable energy per month for 20 or more blocks per month.

Special Terms and Provisions:

1. Service under this rider may be limited at the sole discretion of the utility, based on the expected amount of renewable energy available, average monthly energy usage of the customer, bill payment and collection histories.

2. Aggregate sales are allowed only for multiple facilities owned by the same entity.

3. The customer may sign up for the program at any time and service will become effective at the beginning of the next full billing period, at which point the customer will be charged for the total number of blocks purchased. The Block Charge for Renewable Energy will not be prorated in the billing period in which a customer signs up for service under this rider.

4. If the customer uses less total energy than the number of blocks purchased in any given month, the customer will be charged for the total number of blocks purchased in that month.

5. The customer may cancel their service under this rider at any time; however, any change in service will only become effective at the beginning of the next full billing period. The Block Charge for Renewable Energy will not be prorated in the billing period in which the customer cancels.

6. The utility shall have on file a copy of the latest Schedule for Renewable Energy Service from its wholesale supplier.

RATE FILE

Sheet No.	1 of 1
Schedule No.	RER-2
Amendment No.	APDX

Public Service Commission of Wisconsin

KAUKAUNA UTILITY

Industrial Renewable Energy Rider

This schedule is cancelled. All customers transferred to RER-1.

ELECTRIC RULES

GENERAL SERVICE AND EXTENSION RULES
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101 CONTRACT PROVISIONS

101.1 Term of Contract

All agreements for service shall be for a period of one year unless otherwise specified in the contract. Contracts are automatically renewed at the end of their term under conditions stated in the contract.

No agent or employee of the utility shall have the power to, or shall amend, modify, alter, or waive any of the rates or rules of the utility or bind the utility by making any representation not incorporated in the contract.

Contracts shall not be transferred unless authorized by the utility; new occupants of premises previously receiving service must make official application to the utility before commencing the use of service.

Customers who have been receiving service must notify the utility when discontinuing service; otherwise, they will be liable for the use of the service by their successors should said successors refuse to pay.

101.2 Definitions and Classification of Customers

An electric customer or unit of service shall consist of any contiguous aggregation of space or area occupied for a distinct purpose such as a residence, apartment, flat, store, farm, office, factory, etc., which is equipped with one or more fixtures for rendering service separate and distinct from other users. The public portions of buildings, such as hallways, toilets, etc., may be treated separately depending on the requirements.

Unless otherwise defined, the ultimate use of energy purchased by the customer(s) determines the rate schedule applicable to their installation. Electric customers in general may be classified as follows:

Residential Customers
General Service Customers
Power Service Customers
Public Street and Highway Lighting Customers
Miscellaneous Customers

ELECTRIC RULES

101.2 Definition and Classification of Customers (continued)

101.2a Residential Customers

A residential customer is defined to include each separate house, apartment, flat or other living quarters occupied by a person or persons constituting a distinct household and using energy for general household purposes. Lighting use may be extended to include the use of energy for lighting the land and buildings which are adjacent to, connected with, and used exclusively by the residence being served.

101.2b General Service Customers

A general service customer is defined to include each separate business enterprise, occupation or institution, taking service through a single meter, occupying for its exclusive use any unit or units of space such as an entire building, entire floor, suite of rooms or a single room, and using energy for general purposes as the schedule of rates applicable to the particular installation may permit.

101.2c Power Service Customers

A power service customer is defined to include each residence, separate business enterprise or institution occupying for its exclusive use, any unit or units of space, such as an entire building, entire floor, suite of rooms or a single room, and using energy for driving motors or other electrical loads larger than permitted on the utility's other rate schedules.

101.2d Public Street and Highway Lighting Customers

A public street or highway lighting customer is defined to include governmental agencies that take service for the purpose of lighting public streets, highways or traffic signs.

101.2e Miscellaneous Customers

Customers using electric service for purposes not included in the above classifications are defined as miscellaneous customers.

ELECTRIC RULES

101.3 Application of Rates and Combined Metering

The schedules of rates apply when electricity is furnished in any month to one customer at one location for a class of service through one meter. The schedules of rates are based on delivery and billing service to the ultimate user for retail service and do not permit resale or distribution.

For all extensions of new or increased service, each unit must be separately metered before service will be rendered.

Where a customer occupies more than one unit of space, each unit will be metered separately and a separate bill will be computed and rendered based on the readings of each individual meter unless a customer makes arrangements with a utility to provide the approved circuits and loops by which the different units can be connected and all energy metered through one meter.

Where a commercial and one or more residential units are combined so as to obtain electric service through one meter, the general service rate will be applied.

101.4 Availability of Service Voltages

Service may be taken at the following service voltages:

Single-phase	120 volt 2 wire
	120/240 volt 3 wire
Three-phase	120/208 volt 4 wire-wye
	120/240 volt 4 wire-delta
	277/480 volt 4 wire-wye

Other specific voltages may be available, if approved by the utility.

101.5 Dual Voltages

If a customer requires service at a voltage other than that offered by the utility or at more than one voltage, the customer shall furnish and maintain the additional equipment required. If the customer's service requires two or more transformer settings or points of delivery to a structure, the customer shall also furnish and maintain the additional equipment required.

101.6 Emergency Systems

Where emergency systems in buildings are so wired as to require a separate meter, the energy so metered will be billed as a separate customer. Emergency systems are systems supplying power and illumination essential to safety, life and property where such systems or circuits are legally required by municipal, state, federal or other codes, or by any governmental agency having jurisdiction.

Emergency illumination shall include only the required exit lights and other lights specified as necessary to provide sufficient illumination.

102 OTHER PROVISIONS

102.1 Payment Not Honored by Financial Institution Charge (S*ee* Schedule OC-1)

102.2 Reconnection Billing (S*ee* Schedule OC-1)

102.3 Reconnection of a Seasonal Customer's Service (S*ee* Schedule OC-1)

102.4 Overbilling of Customers

In the event the utility becomes aware of an overbilling of a customer, the utility shall promptly correct the billing error and notify the customer of the circumstances surrounding the overbilling. The utility shall then determine the time period during which the overbilling occurred. In making this determination, the utility shall apply Public Service Commission of Wisconsin rules and utility rules and tariffs.

Once the utility has determined the period of overbilling, the utility shall calculate the amount that it has overbilled the customer. The utility shall then make a refund to the customer of the amount of the overbilling, together with interest as calculated pursuant to Wis. Admin. Code ch. PSC 113.

All overbilling disputes arising under this section shall be taken to the PSC for resolution.

ELECTRIC RULES

103 DEFINITION OF DISTRIBUTION AND SERVICE FACILITIES

103.1 Overhead Service Drop

The overhead service drop is the overhead wire between the last pole or other aerial support of the distribution system and the point of attachment to the customer's service entrance equipment. It is normally located over the customer's property.

103.2 Underground Service Lateral

The underground service lateral is the underground service wire between the distribution system, including any risers at a pole or other structure, and the service entrance equipment. It is normally located on the customer's property.

103.3 Distribution Facilities

All primary and secondary voltage wire or cable and its supports, trenches, connection equipment, enclosures, and control equipment which is used to extend the distribution system from existing facilities to a point of connection with the service facilities. The cost of right-of-way preparation and restoration to the original condition, where appropriate, shall be included in the cost of distribution facilities.

103.4 Underground Service Extension

Consists of an underground service lateral and necessary distribution line, if any. In no case shall it consist of separate segments of underground construction separated by overhead construction. The length of each underground service extension shall be the length of the cable route from the beginning of the trench to the point of termination at the applicant's service facilities.

103.5 Service Entrance Equipment

Consists of the meter socket and related overhead masthead or conduit for underground service. This equipment is provided by the customer and is generally located on or in the customer's building.

103.6 Service Facilities

The service facilities include the standard transformer, standard overhead service drop or standard underground service lateral and standard meter.

ELECTRIC RULES

104 UTILITY FACILITIES ON CUSTOMER'S PREMISES

This rule shall apply to the distribution facilities required to service either a group of customers in multi-tenancy premises or a single customer where, in either case, the utility finds that it is necessary to install portions of such facilities on the premises being served. Such customer or property owner, when requested by the utility, shall make provision on their property for the installation of utility-owned facilities required for service(s) in accordance with the following:

Utility facilities shall consist of those which, in the opinion of the utility, are necessary to furnish adequate service at the utility-owned junction boxes on or adjacent to the enclosure of the utility substation or at customer-owned service entrance facilities. The utility will not supply wiring in or on a building beyond the junction box or on a building beyond the service entrance facilities. The utility will design such installations and will install facilities, which in its opinion are most economical or feasible to the utility, under the conditions met. At each installation the utility shall have the option of extending its primary conductors to two or more substations conveniently located with respect to the customers to be served or to furnish service to all customers from the substation. Where the utility's installation is located in a property owner's building, the applicable provisions of the Wisconsin State Electrical Code shall be observed.

A customer or property owner shall furnish, own and maintain the necessary indoor conduits, indoor or outdoor enclosures, vaults, building structural supports and accessories as specified by the utility.

If a customer or property owner requests any changes in the plan proposed by the utility, the customer shall pay the utility the estimated excess cost of the substituted installation. The utility may require that these costs be paid in advance of construction or may, at the utility's option, offer customers an installment payment plan.

105 CUSTOMERS' RESPONSIBILITY FOR UTILITY'S EQUIPMENT

The customer shall be responsible for all damage to the utility's equipment, and for all loss resulting from interference or tampering therewith, caused by the customer or the customer's permittees, including compensation for consumed energy not recorded upon the meter. (S*ee* Wis. Admin. Code ch. PSC 113.)

Meters, service entrance switches, and service entrance outlets are sealed by the utility and such seals shall not be broken or tampered with in any manner without the consent of the utility except in cases of emergency. The utility should be notified as soon as possible after a seal has been broken.

ELECTRIC RULES

106 EXTENSION OF NEW SERVICE FACILITIES

106.1 Application For Extension of New Service

Each request for extension of new service will require a written application for service in which the applicant agrees to pay any required contribution in aid of construction. The utility may require that the contribution in aid of construction be paid in advance of construction or may, at the utility's option, offer customers an installment payment plan.

106.2 Wiring Affidavit

The contractor or person responsible for the installation of the customer's electric wiring, appliances and other equipment related to each type of service shall deliver a notarized affidavit on a form supplied by the utility attesting to the fact that the work complies with the Wisconsin State Electrical Code and the service rules of the utility. Affidavits must clearly indicate the nature of the work done (such as residential wiring, residential fixtures, garage wiring, range, heaters, motors, or other wiring or equipment). For those cases involving wiring changes or additions which require the meter(s) to be replaced or relocated, or which require inspection by the utility, the affidavit shall include an itemized copy of the connected load, including lights, motors and appliances. Where such changes require new service entrances at a new location, the existing service entrance should not be disconnected before the new service entrance is ready for connection and operation.

If, upon inspection by the utility, installations are found to contain discrepancies, such discrepancies shall be corrected before permanent connection of service will be completed. Or, at its option, the utility may mail the customer a written request demanding conformity within a 10-day period or any prior service connection made by the utility will be disconnected.

The utility normally connects the service entrance wires to the service wires. No one else shall make these connections without the specific approval from the utility, in which case the customer shall assume responsibility for any damage that may result from making these connections. The utility will not be responsible for damage or injury resulting from unauthorized disconnection or reconnection of service wires.

106.3 Ownership of Extension

The title to every extension at all times is with the utility. The utility reserves the right at all times to add additional customers to an extension and make new extensions to an existing extension, under the provisions of these rules, without procuring the consent of any customer or customers contributing to the original construction costs, and without incurring any liability for refunding contributions except as additional customers may be added as provided for herein. (*See* Wis. Admin. Code ch. PSC 113, Refunds.)

ELECTRIC RULES

106.4 Right-of-way For Extensions

106.4a Overhead Facilities

The applicant(s) for service shall furnish right-of-way easements and permits with clearing rights, without cost to the utility adequate for the line extensions necessary to serve them and along a route approved by the utility. Clearing shall either:

(1.) Be done by the applicant(s); or

(2.) Be done by the utility. In this case, the applicant shall, in advance of the clearing work, make a contribution to the utility in an amount equal to the utility's estimate of the cost thereof. Such a contribution shall be nonrefundable, except that after completion of the extension the utility will determine the actual cost of clearing work, recompute the contribution required, and will refund the excess, if any, of the contribution over that required as based on such actual cost.

106.4b Underground Facilities

The applicant(s) shall secure for the utility, without cost to the utility, such easements as the utility may require for the installation, maintenance or replacement of the underground lateral and necessary distribution line extension.

The applicant shall inform the utility of any known or expected underground obstructions within the cable routes on their property (septic tanks, drainage tile, etc.). Any earth fill added to bring the cable route to final grade prior to the underground construction shall not contain large rocks, boulders, debris or rubbish.

In the event of future changes in grade levels by the customer that would materially change the depth of cover over underground conductors, or affect transformer locations, the landowner shall notify the utility in advance of grading, and shall pay the utility its cost of moving or replacing its equipment to accommodate the change in grade. Such charge will also be made for changes in buildings, structures, foundations, walls, or other obstructions.

106.5 Construction Standards and Facilities Provided by Utility

The utility shall provide safe, reliable service with extensions that conform, to the extent possible, to each of the following standards:

ELECTRIC RULES

106.5 Construction Standards and Facilities Provided by Utility (continued)

(1.) Route: The utility shall make the extension over the most direct route that is the least expensive and least environmentally degrading. The customer shall provide or shall be responsible for the cost of all right-of-way easements, and permits necessary for the utility to install, maintain or replace distribution facilities. The customer shall either clear and grade such property or pay the utility to clear and grade such property. The customer is responsible for the cost of restoration of the property after the utility has completed installation and backfilling where applicable.

(2.) Design: The utility shall design and install facilities to deliver service to the customer and the area at the lowest reasonable cost. The facilities shall comply with accepted engineering and planning practices. The design shall consider reasonable needs for probable growth in the area and local land use planning. Unwarranted excess capacity that would result in unnecessary cost increases to the utility and its customers shall be avoided. The utility shall be responsible for the incremental cost of distribution facilities that are in excess of standard design for the customer and normal area growth.

(3.) Efficient Use: The utility's extension rules shall discourage the inefficient use of electricity by appropriately relating costs to the charges made for extensions.

(4.) Cost Estimates: The utility shall engineer and estimate the cost of each extension based on reasonable current costs. Current costs may be estimated using job specific costs, average costs per foot or unit, or other costing method as appropriate.

106.6 Point of Termination

The applicant for new service may select, with the approval of the utility, the point at which the utility will deliver service at applicant-owned terminating facilities. The applicant will furnish, own and maintain circuits, meter socket and equipment beyond such point, except for metering equipment.

It is necessary that a customer's service entrance facilities be located at a point most readily accessible to the utility's distribution system. It is desirable, and often necessary, to avoid crossing adjacent property with service drops or laterals. If the distribution system is established in the rear of the premises, the service entrance must be brought to the rear of the building. Where the distribution system is located on the street or where no distribution system has been established, the customer shall request the utility to specify an acceptable location of the service entrance facilities. The utility will furnish this information in writing upon request.

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106.7 Meters

Meters will be furnished and installed by the utility. The customer, however, must furnish the meter socket and all necessary extra wiring to meet the meter connection and must furnish a safe and convenient place for the meter(s).

In the event a customer desires an additional meter installed for his or her own convenience, the installation shall be entirely at the cost of the customer, including the cost of the meter.

106.8 Metering Facilities

The customer shall install the meter socket on the exterior of the building.

In rural areas, a yard pole may be furnished by the utility and located at a point central to the buildings to be served. In this case, the customer shall install the meter socket on the yard pole. All service equipment beyond this point is the responsibility of the customer.

When only a residence is built in the rural area and underground service is used, the meter may be placed on the pole if permission is obtained from the utility prior to installation. A customer-owned yard light may not be installed on this pole unless permission is obtained from the utility. The customer is responsible for the location of the meter socket. If it is located other than as described above, the customer must obtain writing permission from the utility prior to installation or the customer shall move the meter socket to conform to the utility standards.

106.9 Number of Service Drops or Laterals Per Customer

The utility shall provide standard overhead service drops and standard underground service laterals at no charge to the customers.

Not more than one service drop or service lateral will be installed to the same building or utilization point except:

(1.) Where more than one point of delivery is necessary because of voltage regulation, governmental requirements or regulatory orders.

(2.) In a large installation (large power only) where, in the opinion of the utility, more than one service drop or lateral is necessary to meet the load requirements.

(3.) In row houses and other multiple occupancy buildings having areas separated by firewalls in compliance with the Wisconsin State Electrical Code.

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106.9 Number of Service Drops or Laterals Per Customer (continued)

If an existing customer with a single-phase service drop or lateral requests three-phase service, the customer shall rewire their equipment to operate from the three-phase service drop or lateral before three-phase service will be extended. The single-phase service drop or lateral will be removed from service after the three-phase service has been extended.

106.10 Overhead Service Drop

A standard overhead service drop shall be furnished by the utility to a suitable support on the customer's premises. The utility will provide supplemental information to the customer indicating the equipment that the customer shall install, own and maintain. This material will also indicate what Wisconsin State Electric Code provisions and city ordinances must be complied with for the installation of this equipment.

106.11 Underground Service Lateral

A standard underground service lateral shall be furnished by the utility to suitable service equipment on the customer's premises. This equipment shall be installed on the customer's building at a location approved by the utility.

The utility will provide supplemental information indicating what equipment the customer shall install, own and maintain for underground service and indicate what provisions of the Wisconsin State Electric Code and city ordinances must be complied with for the installation of this equipment.

106.12 Transformers

The utility shall provide standard design transformers necessary to serve the customer's load at no charge.

A standard design transformer is a transformer with capacity less than or equal to 112.5 kVA. If a customer requests or requires additional capacity, the utility shall add to the total cost of installation a charge equal to the cost of the necessary transformer(s) less a credit for the cost of the maximum capacity standard transformer.

106.13 Nonstandard Service Facilities

If the proposed extension requires nonstandard service facilities or if the customer requests nonstandard facilities, the utility may require that the customer pay a contribution in advance of construction for the cost of the facilities in excess of the cost of standard design facilities.

106.14 Extraordinary Investment by Utility for Extension

Proposed extensions may be reviewed for economic considerations. If the cost of an extension exceeds five times the average embedded cost to serve a customer in the same class as the customer for whom the extension is to be made, the utility may require a contract with the customer. Under the terms of the contract, the customer may be required to pay the recurring estimated operation and maintenance expenses associated with that portion of the extension that is in excess of five times the average embedded cost at the time the extension was made. The reasons and supporting analysis for each contract will be furnished the customer and the Public Service Commission of Wisconsin (Commission), in writing. The utility will inform the customer of the customer's right to ask the Commission for a review of the extension costs and contract provisions. The utility will notify the Commission in writing, when a service extension is denied, including the reasons for denial.

107 INSTALLATION CHARGES AND EMBEDDED COST CREDITS

107.1 Definition of Equipment, Installation Charges and Embedded Cost Credits

For purposes of implementing these installation charges the following definitions shall apply:

107.1a Customer Classifications

Customer classifications are based on usage characteristics. Each classification has a distinct installation charge and embedded cost credit. For definitions of distribution and service facilities installed in new installations see Section 103. Examples of customer classifications are as follows:

(1.) Residential Service
(2.) General Service
(3.) Power Service
(4.) Street Lighting

107.1b Total Cost of Installation

The total cost of an extension shall be defined as the cost of the extension of primary and secondary lines, (excluding the standard meter, the necessary standard service drop or service lateral and individual standard transformer capacity); reconstruction of existing main feeders including changing from single-phase to three-phase or construction of new feeders made necessary solely by addition of such customers; the cost of tree trimming or right of way clearing; securing easements; moving conflicting facilities; and all other costs incidental to furnishing service. The customer is responsible for the cost of restoration of the property after the utility has completed installation and backfilling where applicable. This definition applies to both overhead and underground distribution systems. If it is found to be advisable for the utility to install facilities in excess of that required to serve the new customer applying for service, the added cost of these facilities will not be used in determining the cost of the extension.

107.1c Installation Charge

The installation charge is the total cost of installation less the average depreciated embedded cost of the distribution system (excluding cost of the standard transformer and service facilities). Seasonal customers shall receive one-half the average embedded cost allowance of a year-round customer for the same customer classification.

107.1d Average Depreciated Embedded Cost

The Public Service Commission of Wisconsin determines the embedded cost of the distribution system (excluding the standard transformer and service facilities) for each customer classification, as indicated below. The average depreciated embedded cost by customer classification is listed in Schedule OC-1.

(1.) Residential Service: The average depreciated embedded cost is determined by dividing the original cost less the estimated accrued depreciation of the distribution system and less customer contributions and advances for construction allocated to this customer classification by the number of customers in the group.

(2.) Apartment and Rental Units Separately Metered: The owner of an apartment or rental unit applying for an extension of service shall receive the same average depreciated embedded cost credit, that applies for residential service, per unit metered.

107.1d Average Depreciated Embedded Cost (continued)

(3.) Subdividers and Residential Developers: The same average depreciated embedded cost credit, that applies for residential service, would apply per unit energized within five years from the installation of the contributed extension.

(4.) General Service (Including Multi-Unit Dwellings If Billed on One Meter): The average depreciated embedded cost credit is determined the same way as Residential.

(5.) Power Service: The embedded allowance is determined by dividing the original cost less the estimated accrued depreciation of the distribution system and less customer contributions and advances for construction allocated to this customer classification by the estimated average billed demand of these customers. When there is an upgrade, the average billed demand is the difference between the averaged billed demand before and after the upgrade.

(6.) Street Lighting: The dollar amount per fixture is determined by dividing the overall depreciated cost of the distribution facilities allocated to the street lighting class, less credits for past customer contributions and advances for construction, by the total number of lighting fixtures in that classification.

All average depreciated embedded costs (by rate class) shall be subject to review by the Public Service Commission of Wisconsin, as part of each general rate case proceeding.

107.2 Total Cost of Installation by Customer Classification

107.2a Residential, General Service, Power Service, and Street Lighting Classes:

Will be charged the total installation cost less the average depreciated embedded cost as defined in Section 107.1d.

107.2b Residential and Commercial Developers and Subdividers:

Residential and Commercial developers and subdividers of single- and two-family subdivisions shall pay, as a minimum, a partially refundable contribution which is the estimated cost of distribution facilities to be installed for the area being developed. The average depreciated embedded cost is refundable as structures are built and connected to the electric utility facilities, as defined in Section 107.1d.

107.2c Installation Charges for Multi-Family Residential Housing Units:

Will be the total installation cost less the average depreciated embedded cost, as defined in Section 107.1d, per each living unit in the multi-family building.

107.2d Other Installation Charges

In addition to the installation charges provided above, the utility may require the customer to pay, in advance of construction, the estimated direct costs for those distribution service facilities which,

(1.) Are in excess of standard utility design and construction,

(2.) Follow a route different than the most direct route as in Wis. Admin. Code ch. PSC 113, as determined by the utility, or

(3.) Require abnormally high installation costs due to abnormal soil conditions, including trenching in rocky soil, frozen ground, or other similar conditions. (Winter construction will normally apply between December 1 and April 1.)

All such payments for these conditions are subject to partial refund as additional customers connect.

107.2e Adjustments to Estimates of the Total Cost of Installation

Section 107.2 explains the method for estimating the total cost of installation. The utility shall adjust its estimate of construction costs to reflect the costs that are actually incurred. If the cost of installation differs from the utility's original cost estimate, a recalculation of the customer contribution shall be made.

108 REFUNDS OF CUSTOMER CONTRIBUTIONS BY TYPE OF CUSTOMER

108.1 Eligibility for Refunds

The utility shall make refunds to a customer who made a contribution for an extension (a contributed extension) when the utility makes an extension from the contributed extension to a second customer that does not require a contribution from the second customer (a non-contributed extension).

In all cases, refunds to the customer making the original contributions shall be limited to the first five years from the installation date. The utility shall make the refund to the customer who made the original contribution or the current property owner of record unless it has a written record from that customer assigning the refund rights to another customer.

108.2 Application of the Refund

(1.) When additional customers are connected to an existing extension, which required an installation charge from the original customer for whom the extension was first made, that original customer may receive a refund from the utility.

(2.) If the cost of adding a new customer to an existing extension is less than the average depreciated embedded cost, the new customer will be charged nothing. The original contributor of the extension shall be refunded the difference between the average depreciated embedded cost and the cost of adding the new customer.

(3.) If the cost of additional distribution facilities exceeds the average depreciated embedded cost of a customer classification, the construction will be considered a new extension. In this case no refund is due the original contributor.

(4.) The original contributor shall receive refunds, if any, for only the first five years from the date the original extension is energized.

(5.) Refunds shall be made to the original contributing customer by the utility within 20 days after the additional customer's cost of installation is determined.

The amount of the refund shall be based on the embedded cost allowance in effect at the time the contributed extension was installed, or the current embedded cost allowance, whichever is greater. In no case shall the total refund exceed the total installation charge.

109 OVERHEAD SERVICE EXTENSIONS

109.1 Applicability

The rules of this section apply to the extension of overhead electric service to all classes of retail customers requesting new service in all areas served by the utility.

The utility will extend electric service to a new customer(s) or existing customer(s) furnished by means of extending its overhead distribution system, except that three-phase service may be furnished by means of phase conversion equipment from a single-phase line.

109.2 Contributions for Overhead Extension

The charge for all overhead extensions shall be the total cost of installation as defined in Section 107.2 less the average depreciated embedded cost. (S*ee* Section 107.1d)

109.3 Combination Single-Phase and Three-Phase Construction

In the event an extension is partially or completely supported on structures used for supporting transmission circuits, or in the event the extension is built to serve both single-phase customers and three-phase customers, the utility will compute, and apportion among the customers served, the extension contribution requirements and contribution refund rights in a fair and equitable manner consistent with the pertinent facts, and will retain in its files a memorandum of such computation and apportionment. The contribution requirement of the single-phase customers shall not be greater than would have been the case if an extension (complying with present engineering standards) had been constructed to serve only the single-phase customers.

110 UNDERGROUND SERVICE EXTENSIONS

110.1 General Rules on Underground Service Extensions

The utility will extend utility-standard underground service to all classes of retail customers requesting new service in all areas served by the utility.

110.2 Stipulations on Availability of Underground Service Extensions

Underground service extensions to be furnished by the utility are limited to those which may be placed in locations where grade levels and other conditions are satisfactory to the utility, such as across residential or farm yards or commercial premises or along driveways. The route of the underground construction must be clear of any trees, brush, fences or other surface obstructions that would interfere with normal operation of trenching equipment. Trench backfill shall consist of the original soil and shall not be power tamped. Lawn and landscaping restoration shall be the applicant's responsibility.

Underground service extension in locations such as beneath undeveloped land, quarries, gravel pits, swamps and water will not be furnished except by written approval of the utility for each installation.

The utility will not install an underground service extension where engineering, operating, construction, safety or legal problems would, in the utility's judgment, make it inadvisable to perform the installation, unless these problems can be resolved by the payment of contributions and/or the charges as provided for in these extension rules.

Notification must be given to the utility sufficiently in advance of construction so that a sequence of construction can be provided for and the work coordinated with other utilities involved.

110.2 Stipulations on Availability of Underground Service Extensions (continued)

If the trench cannot for any reason be dug prior to the freezing of the soil, the utility may temporarily install secondary voltage conductors in suitable mechanical protection on top of the ground and dig the trench when the ground is thawed.

The utility shall not be prevented from installing underground electric equipment where necessary by reason of physical conditions or congestion in the area, when this type of construction is the most economical type for the conditions.

110.3 Contributions for Underground Extensions

The charge for all underground extensions shall be the total cost of the installation as defined in Section 107, less the average depreciated embedded cost as defined in Section 107.1d.

110.4 Contribution for Added Costs Due to Unusual Conditions

For unusual construction costs a contribution is required which may be subject to a partial refund as additional customers attach. The cost shall include:

(1.) An amount equal to the estimated cost of boring or pavement cutting required or where conductors must be installed in rocky soil, frozen ground, or other similar conditions.

(2.) An amount equal to the cost of any special requirements such as municipal requirements, rearrangement of facilities due to a change of plans or the need for an underground service extension different from or more elaborate than the utility's standard underground construction.

(3.) An amount equal to the estimated additional cost for trenching through any area where normal plowing and trenching methods cannot be used, for example, ledge rock, boulders, land-fill, etc.

Upon completion of the construction, if the actual amount of such extra cost is less than the estimated amount, the utility will refund the difference between the estimated and actual costs.

ELECTRIC RULES

110.5 Combination of Overhead and Underground Extension

In accepting an application for underground electric service under this schedule, the utility does not undertake to avoid the construction of overhead lines in the neighborhood, which may be necessary to serve customers who demand and have the right to receive service from overhead lines. However, in order to avoid duplication of facilities, applicants for electric service whose premises can be served from an underground distribution system that has previously been installed adjacent to the applicant's premises shall be required to be served by an underground lateral from such system and shall pay the contributions and charges required in these extension rules.

110.6 Underground Distribution Areas

110.6a General Rules on Underground Distribution Areas

The utility will install utility-standard single-phase underground electric distribution system in accordance with this schedule where required by ordinance or when requested by and agreed to by the property owner(s) or developer or subdivider of the land area to be served. (However, all lines exceeding 15,000 volts in such areas may be overhead.)

Electric distribution facilities provided for under this rule are only for providing service to permanent buildings. The utility will own and maintain the underground conductors and appurtenances, and the character and location of such facilities shall be at the discretion of the utility.

110.6b Establishment of Underground Distribution Areas

(1.) Subdivisions

a. For purposes of this schedule a subdivision shall be defined as a division of lands consisting of five or more contiguous lots. Lots directly across a street from each other are considered to be contiguous.

b. To qualify as an underground distribution area the property owner(s) or land developer or subdivider shall have provided a suitable recorded plat of the subdivision with deed restrictions, all satisfactory to the utility, to require all utility service to be supplied by underground lines and prohibiting overhead lines, except for lines exceeding 15,000 volts, and with easements shown.

110.6b Establishment of Underground Distribution Areas (continued)

c. An area that qualifies as a subdivision may be established as an underground distribution area in either of the two following ways:

(1) All new subdivisions not already receiving electric service are defined as underground distribution areas where by ordinance the electric distribution systems are required to be underground.

(2) A group of property owners or land developer or subdivider may request that an area be served by an underground distribution system. Such area shall be specifically defined and of reasonably regular shape.

(2.) Mobile Home Courts: A new mobile home court or an expansion of an existing mobile home court, may be established as an under-ground distribution area where:

a. The court consists of five or more established mobile home locations, all of which are contiguous.

b. Occupancy of the mobile homes is to be on a year-round basis.

c. The owner of the mobile home court provides the utility a written commitment that all utility service will be supplied by underground lines and prohibiting any overhead lines, except for lines exceeding 15,000 volts.

(3.) Condominium Developments and Apartment House Complexes: A new residential condominium development, apartment house complex or an expansion of an existing such housing facility may be established as an underground distribution area where:

a. The condominium or apartment complex consists of five or more dwelling units.

b. The developer provides the utility a written commitment that all utility service will be supplied by underground lines and prohibiting any overhead lines, except for lines exceeding 15,000 volts.

110.6b Establishment of Underground Distribution Areas (continued)

(4.) Easements: The property owner(s) or land developer or subdivider shall have secured for the utility, at no cost to the utility, such easements as the utility may require for the installation, operation and maintenance of its facilities including but not limited to easements for its transformers and switches. The property owner(s) or land developer or subdivider shall inform the utility of any known or expected underground obstructions within the cable routes. Any earth fill added to easements to bring the grade to final level shall not contain any large rocks, boulders, debris or rubbish.

In subdivisions, easements shall be provided along side lot lines as necessary for underground cables to street light locations approved by appropriate governmental authority.

(5.) Expansion of Underground Distribution Areas: An established underground distribution area may be expanded to include such lots or building sites as are contiguous to it which are not already served by overhead lines. The owners of such lots shall be responsible for seeing that the lots meet the requirements specified above for the underground distribution area to which it is contiguous.

110.6c Contribution and Charges for Extension

(1.) Contribution for Construction Within Underground Distribution Area: All of the provisions of contributions for construction of underground extensions will apply except that the extension allowance will apply to those lots at which dwelling units are occupied or under construction (construction has proceeded above the foundation level) only. The utility may require that the contribution in aid of construction be paid in advance of construction or may, at the utility's option, offer the property owner(s), land developer, or subdivider an installment payment plan.

(2.) Distribution Line to Underground Distribution Area: Where an extension of the utility's existing distribution system is required in order to reach the underground distribution area, said extension will normally be overhead construction. The extension allowance for the overhead distribution line will apply to those lots on which dwelling units are occupied or under construction (construction beyond the foundation level) only. The utility may require that the contribution in aid of construction be paid in advance of construction or may, at the utility's option, offer customers an installment payment plan. If required by statute or ordinance, or if required by the conditions in the judgment of the utility, all or a portion of the extension will be underground. A refundable contribution as provided in Section 110.6c(1), will apply.

ELECTRIC RULES

111 MODIFICATIONS TO EXISTING DISTRIBUTION AND SERVICE FACILITIES

111.1 Relocation and Rebuilding of Existing Distribution Facilities

(1.) Where responsibility can be determined by the utility, the customer responsible for relocation, rebuilding, or other modification of existing distribution facilities shall pay a contribution based on the following:

Estimated direct cost of new facilities
Less: Accrued depreciation of facilities to be removed
Less: Estimated net salvage of the facilities to be removed
Plus: Estimated cost of removal of existing distribution facilities
Equals: Charge for modifications to existing facilities

The costs and credits of the above shall be determined from the available records of the utility. The utility shall endeavor to maintain records that permit a reasonable calculation of these costs and credits. The contribution shall be refundable when the extension is less than the embedded allowance as per Section 108, Refunds to Customers.

(2.) Where the utility chooses to relocate its distribution system and it is practicable to bring a service drop or lateral to the existing service entrance facilities, the utility will make the necessary changes in the customer's wiring and service equipment without expense to the customer.

(3.) In the event that the utility is ordered by a unit of government to move its distribution facilities, a new service drop will be installed, where practicable, to the existing service location without expense to the customer. If, in the opinion of the utility, it is not practicable to utilize the existing service entrance facilities, the utility will specify a new service location. The utility is not required to furnish new service entrance, cable, conduct, or service equipment unless it makes a practice of supplying this equipment. The utility shall, however, run a service drop to the nearest point on each building served from the new location and remove the old service drop without expense to the customer.

111.2 Replacement of Overhead Distribution Facilities with Underground Distribution Facilities

A customer requesting the utility to replace existing overhead distribution facilities with underground distribution facilities shall pay the contribution in aid of construction and receive refunds as shown in Section 111.1(1) above.

111.3 Upgrade of Distribution Facilities Due to Change in Load

Customers who request an upgrading of the utility distribution facilities due to a change in the character of their load shall pay for the construction costs incurred by the utility to provide the requested additional facilities.

(1.) Demand Schedule: Customers who are served under a demand rate schedule shall receive an embedded cost allowance. The kilowatts of demand to be used in determining the allowance shall be the customer's average billed demand after the upgrade less the customer's average billed demand before the upgrade.

(2.) Customers Transferring to a Different Energy-Only Classification: If a customer served under an energy-only sub-classification prior to the upgrade qualifies for a different energy-only sub-classification after the upgrade, the customer shall receive a cost allowance equal to the difference between the two embedded cost allowances.

(3.) Customers Transferring to a Demand Classification: If a customer is served under an energy-only classification prior to the upgrade, the customer shall receive an embedded cost allowance. The kilowatts of demand to be used in determining the allowance shall be the customer's average billed demand after the upgrade less an estimate of the customer's prior average demand.

111.4 Upgrade of Service Facilities

(1.) Overhead Service Drop: The utility shall not charge the customer to upgrade an overhead service drop with a larger size overhead service drop up to the maximum standard size.

(2.) Underground Service Lateral: The utility shall not charge the customer to upgrade an underground service lateral with a larger size underground service lateral up to the maximum standard size.

(3.) Overhead Service Drop to Underground Service Lateral: The utility shall require a contribution from a customer requesting to have an overhead service drop upgraded to an underground service lateral. The contribution shall be equal to the cost of the underground service lateral less the cost of an equivalent overhead service drop.

(4.) Transformers: The utility shall not charge the customers to upgrade their transformer to the maximum standard capacity.

ELECTRIC RULES

112 EXTENSIONS OR MODIFICATIONS OF TRANSMISSION FACILITIES TO RETAIL CUSTOMERS

Before a utility extends or modifies its transmission facilities to a retail customer, the utility shall require a contract between the utility and the customer which describes the facilities to be constructed, such as the cost of construction, apportions the responsibility for the construction costs between the utility and the customer, and provides a supporting analysis for the construction and the cost apportionment. The utility shall submit the contract to the Commission for approval. The Commission shall review the contract to assess whether existing ratepayers would be adversely affected by the proposed extension or modification. If the Commission does not respond to the utility within 20 working days from the date of receipt, the contract is approved.

113 TEMPORARY SERVICE

The utility will extend its service to fairs, carnivals and like short-time gatherings and uses (not including short-time uses in the nature of auxiliary, stand-by or seasonal use) under the following rules:

(1.) The customer will agree to reimburse the utility for its expenditures in extending service.

(2.) The cost of extending service shall include all items of labor and materials, with the customary overhead charges, necessary to furnish the customer with the service requested. It shall also include any costs involved in the dismantling of materials and their return to stock. Where materials dismantled have a salvage value, the cost of extending service will be credited with such salvage value.

(3.) All energy will be measured at one standard voltage at some convenient point designated by the utility.

(4.) The customer will make the necessary arrangements and provide for the necessary equipment in the event more than one voltage is required.

(5.) The cost of all construction (labor and materials) necessary to distribute energy on the premises occupied by the customer will be borne by the customer.

(6.) The utility may require the customer to make an advance deposit sufficient to cover the costs of extending service and the estimated bill for energy.

(7.) The rates applicable in the area where temporary service is rendered shall be applied in determining the customer’s bill.

ELECTRIC RULES

114 TEMPORARY SERVICE FOR CONSTRUCTION

(1.) The customer will agree to reimburse the utility for its expenditures in extending service.

(2.) Temporary service shall be given to a customer connection only when constructed in accordance with the sketch as provided by the utility. The post supporting the unit shall be located as near as possible to the location of permanent service to the building. Abnormal conditions involving compliance with the foregoing provision will be cleared with the utility and permission granted by the utility prior to locating the customer connection.

(3.) All temporary service shall be maintained in a safe manner in order to keep the utility harmless from injury to persons or property. The service shall remain temporary only for a reasonable time and must be made permanent when the utility directs such action.

(4.) Should the customer elect to receive permanent service the installation charges for extension of new electric service as provided for in Section 107 will apply. Credit shall be given for the payment already made for that portion of the temporary service facilities that can be used for permanent service without modification.

115 EMERGENCY SERVICE

A customer purchasing electric service from the utility under any of the utility's filed rates for firm service, and requesting a reserve line or a separate service connection other than that from which regular service is obtained should consult the utility to determine if such service is available.

The utility may supply emergency service facilities under the terms of a special contract, providing the customer shall pay all costs associated with such facilities. The utility will then provide the emergency service distribution facilities required.

ELECTRIC RULES

116 GENERAL RULES ON CUSTOMER UTILIZATION EQUIPMENT

The rules in this section are designed to assist in maintaining a high standard of electric service for all classes of customers with maximum economy based on electric service rules of the Public Service Commission of Wisconsin governing the variation of voltage at customer service entrances.

Before installing any utilization equipment, it shall be the customer's responsibility to notify the utility of the planned addition. The utility will advise customers concerning a specific installation on request. The utility will not test or investigate any customer's equipment except when necessary to determine the cause of substandard voltage conditions. The utility shall, at all reasonable times, have the right to enter a customer's premises to examine the customer's equipment. The utility may refuse to connect service or will suspend service when such equipment does not conform to these rules and it has not been corrected after reasonable notice.

All wiring and other electrical equipment on the premises furnished by the customer shall be installed and maintained by the customer at all times in conformity with the requirements of the Wisconsin State Electrical Code and with the Rules and Regulations of the utility.

Electrical apparatus to be used in connection with and operated by energy furnished by the utility shall be of such design and construction, and installed and operated in such manner, so as not to interfere unreasonably with the utility's service to other consumers. In the event that such apparatus does not comply with the above requirements, the utility may discontinue service until the customer has remedied the conditions causing interference with the utility's service to other consumers. The utility may require the installation of a separate power service to serve equipment which does not conform to the rules which govern lighting service or to serve other devices which are likely to interfere with standard voltage regulation.

Where a customer connects single-phase equipment to a three-phase service, the single-phase equipment shall be connected to prevent unbalance of the loads on the three-phase service in excess of 10 percent. Such a customer shall maintain a power factor of 90 percent (or as otherwise specified in the company's tariffs). When these requirements cannot be met, the customer shall apply for a separate single-phase service.

It shall be the customer's responsibility to install any protective devices such as time-delay under-voltage relays, phase reversal relays, devices to protect against unbalanced phase operation of three-phase equipment and any other device necessary to prevent damage to utilization equipment that might result from imperfections in the supply of power.

ELECTRIC RULES

117 MOTORS AND MOTOR CONTROL

In order to prevent impairment of service to other customers, it is necessary to establish limits for the allowable starting currents for motors. Before selecting motor equipment, the customer should consult the utility to determine the specific voltages available at any location.

When a motor is used to drive equipment that requires varying torque during each cycle of operation, such as a compressor or reciprocating pump, the combined installation should have enough momentum in its moving parts so that its operation will not interfere unduly with service to other customers.

(1.) Types of motor service available on general service lighting rates, single-phase only are as follows:

a. Single-phase fractional horsepower motors: Automatically controlled and frequently started, whose locked rotor currents do not exceed 23 amperes may be connected to 120-volt circuits.

b. Single-phase motors, one horsepower or less: Manually controlled or infrequently started, whose locked rotor currents do not exceed 50 amperes may be connected to 120-volt circuits. No single-phase motor larger than 1 horsepower shall be operated on a 120-volt circuit.

c. Infrequently started single-phase motors of 10 horsepower or less may be connected to 240-volt other circuits if their locked rotor currents do not exceed the values shown in the next section describing motor service available on power rates.

d. In urban areas infrequently started three-phase motors of 10 horsepower or less; connected through single-phase to three-phase converters may be used on other circuits.

e. Single-phase motors above 10 horsepower are not permitted in rural areas.

117 MOTORS AND MOTOR CONTROL (continued)

(2.) Types of motor service available on power rates and combined light and power rates, single-phase and three-phase are as follows:

a. Motors with long periods of continuous operation under maximum load conditions and having not more than four starts per hour may be connected if their locked rotor currents do not exceed those listed in the following table. Consult the utility where these conditions cannot be met, or where equipment ratings and/or starting characteristics exceed the values in the table below:

Motor Starting Table

Motors Rated	Total Locked Rotor Current Not to Exceed
120 Volts, Single-Phase	50 Amperes
240 Volts, Single-Phase 2 Horsepower or Less	60 Amperes
2 to 6.5 Horsepower	60 Amperes Plus 20 Amperes Per Horsepower in Excess of 2 Horsepower
6.5 to 15 Horsepower	150 Amperes Plus 10 Amperes Per Horsepower in Excess of 6.5 Horsepower
240 Volts, Three-Phase 2 Horsepower or Less	50 Amperes
2 to 19.9 Horsepower	50 Amperes Plus 14 Amperes Per Horsepower in Excess of 2 Horsepower
20 to 40 Horsepower	300 Amperes Plus 4 Amperes Per Horsepower in Excess of 20 Horsepower
50 Horsepower and Over	8 Amperes Per Horsepower

ELECTRIC RULES

117 MOTORS AND MOTOR CONTROL (continued)

b. Motors above 10 horsepower rating are to be three-phase.

c. New installation of motors of 50 horsepower or larger should be approved by the utility as to motor type, starting and protective equipment, and as to availability of an adequate power supply at the proposed location.

d. Motors subject to frequent starts, such as elevator and hoist motors, when connected to the secondary distribution system, should have their starting current limited to 100 amperes.

e. For motors of higher voltage rating than shown in the motor starting table, the allowable currents are inversely proportional to the voltages.

118 MISCELLANEOUS EQUIPMENT

X-ray equipment operated on lighting or combined lighting and power services shall have input currents not exceeding 24 amperes without specific approval of the utility.

All other equipment not specifically provided for in this section will be subject to approval of the utility on the basis of starting currents specified herein for motors with the same frequency of starting. Customers are advised to consult the utility before connecting any such apparatus.

119 PRIVATE POWER PLANTS

No generator may be electrically connected to the utility's lines or equipment without the written consent of the utility and with adequate physical arrangements to prevent hazard to life and damage to utility property.

119 PRIVATE POWER PLANTS (continued)

After advance written notice and advance approval by the utility, a customer may install their own standby emergency generating equipment and connect it to the customer's wiring systems, provided the connection is through a double-throw switch or other means which will prevent accidental electrical connection of the generator to the utility's facilities at any time. All cost of installation and equipment shall be borne by the customer. The customer shall not operate such equipment until inspection by the utility has been completed. In the event that any customer wishes to engage in parallel operation with the facilities of the utility, service will not be rendered to such customer until a written contract has been entered upon between the customer and the utility and the conditions of delivery of electric energy are fully outlined therein.

See Wis. Admin. Code ch. PSC 114 (Wisconsin State Electrical Code).

120 PAYMENT FOR CONTRIBUTION IN AID OF CONSTRUCTION

The utility may require that the required contribution in aid of construction be paid in advance of construction or may, at the utility's option, offer customers an installment payment plan. If a utility offers an installment payment plan to its customers, the installment plan shall be reviewed and placed on file at the Commission.

121 STRAY VOLTAGE SERVICE

(1.) Under normal operating conditions, a neutral-to-earth current or voltage may exist on the grounded or grounding conductors or other conductive objects on the customer's premises. The source of the current or voltage may be located on the premises, off the premises, or a combination of both. Upon the customer's request, the utility will investigate inquiries associated with neutral-to-earth current or voltage concerns.

(2.) Stray voltage is a 60 Hz steady state AC RMS voltage that can be measured across a 500-ohm shunt resistor, which has been connected between two points that livestock may contact simultaneously. "Steady state" means the value of a current or voltage after all transients have decayed to a negligible value. "Transients" mean changes in the steady state current or voltage caused by faults, operation of protective devices, switching, reclosing, tap changing, motor starts or stops, motor stalls or other phenomena that are temporary in nature. The Public Service Commission of Wisconsin has defined the "level of concern" as 1 volt or 2 milliamperes (mA) AC RMS steady state at cow contact.

(3.) If a customer requests stray voltage investigative analysis more than two times in a 12-month period, and the utility has not found stray voltage above the level of concern in any of these analyses, the utility may charge a fee for any further stray voltage analyses it performs during the remainder of the 12-month period. The fee may not exceed $320, which is estimated to be the cost of the additional requested service.

(4.) Following a determination by the utility that, under normal operating conditions, the contribution to animal contact current from off-farm sources is in excess of 1 mA, the utility shall implement, at its expense, measures to reduce this contribution to below 1.0 mA. For farm facilities housing livestock where stray voltage from off-farm sources is a concern, it may be necessary under certain conditions to modify the farm or utility electrical system, or both.

(5.) The utility shall, based on a technical and economic analysis of acceptable alternatives for lowering levels of stray voltage at the given location, determine whether long-term system modification should be on-farm, off-farm or both. If the utility, with the consent of the customer, chooses to install a long-term mitigation device (e.g., an electronic grounding system or equipotential plane) on farm property, the customer will assume ownership of the device. The utility will respond to reasonable customer requests regarding maintenance of the device. The customer is responsible for the daily monitoring and energy costs of the on-farm mitigation device, if any. The customer may be required to sign a Stray Voltage Reduction Agreement prior to installation of an on-farm mitigation device.

(6.) The utility will not install any mitigation device(s) where its stray voltage investigation reveals unsafe conditions, or the inspection report of a state certified commercial electrical inspector or a state certified master electrician reveals that conditions do not comply with applicable electrical codes. If the utility's investigation reveals unsafe conditions, the utility shall notify the customer of the problems found and the potential hazards, and shall recommend the customer take prompt action to remedy the hazard.

(7.) In the event modification of on-farm or off-farms systems, to reduce off-farm stray voltage contribution, is not required, the customer may request separation of primary and secondary neutrals. The neutral reconnection device(s) ["isolator(s)"] used for this purpose shall be approved for use by the utility and the Public Service Commission of Wisconsin. Prior to installation, the customer shall submit an application form, a satisfactory farm wiring inspection report which has been issued by a state certified commercial electrical inspector or a state certified master electrician, and submit payment for all costs associated with the neutral separation. The customer may be required to sign a Customer Requested Neutral Separation Agreement and may also be required to sign a Hold Harmless/Indemnification Agreement and Release approved by the Public Service Commission of Wisconsin. Separation costs shall include labor, equipment, and materials [excluding the isolator(s)] necessary for both isolator(s) installation and a post-separation analysis of possible bypass circuitry. Costs may vary and may, therefore, be subject to a specific determination for each farm location. The isolator(s) shall be owned by the utility and shall be leased to the customer at a lease rate of $35.00 per isolator, per month. This lease rate includes an appropriate amortized fee to cover the cost of an annual inspection designed to assess isolator effectiveness and to ensure that the isolator(s) continues to perform its intended function of neutral reconnection under fault conditions. Lease agreement shall require monthly billings.

(8.) If within one year of the date of installation of a customer-requested isolator(s), the customer requests isolator(s) removal, the utility shall refund to the customer all lease amounts which the customer has paid to date.

(9.) Where modifications to on-farm or off-farm systems to reduce off-farm contribution is required but cannot be accomplished within five working days, the utility may install a temporary isolator(s). The customer may be required to sign a Temporary Neutral Separation Agreement prior to installation. The utility must remove the isolator(s) and reconnect the neutrals within 90 days, unless it receives a waiver from the Public Service Commission of Wisconsin or the customer completes a Customer Requested Neutral Separation Agreement. Upon receiving a completed Customer Requested Neutral Separation Agreement, the utility (not the customer) will provide the inspection of farm wiring by a state certified master electrician or state certified commercial electrical inspector. If any wiring code violations are found and the customer corrects them within 60 days, the utility will keep the isolator(s) in place. Otherwise, it must remove the isolator(s) and substitute another mitigation technique to reduce off-farm stray voltage to 1.0 mA or less.

ELECTRIC RULES

(10.) Should the customer whose neutrals were temporarily separated as provided for in (9.) above desire the isolator(s) be left in place following the required reduction of off-farm stray voltage contribution, the customer may request the continuation of this service in accordance with the terms and conditions established in (7.) above. The agreement shall be contingent on receipt of a satisfactory wiring inspection report issued by a state certified commercial electrical inspector or a state certified master electrician. Initial installation costs will be waived.

(11.) At farm locations where primary and secondary neutrals have been separated at the request of the customer as provided for in (7.) and (9.) above, cost-free stray voltage investigative services may be limited to an annual investigation that determines the effectiveness of the isolator and isolation and an analysis of utility facilities only. If the customer requests on-farm stray voltage analysis or additional determinations of isolation effectiveness, the Utility may charge a $320 analysis fee.

(12.) Numerous locations exist where primary and secondary neutrals have been separated for various reasons prior to the order date, July 16, 1996. As stray voltage investigations are performed at these locations, either at customer request or incident to existing utility isolator removal efforts or system modifications, and the utility's stray voltage contribution under normal operating conditions is determined to be less then 1.0 mA, these customers shall become subject to all of the conditions set forth above.

(13.) Prior to July 16, 1996, the utilities shall perform the required stray voltage investigation and separate the primary and secondary neutrals within 45 days of the receipt of a Public Service Commission of Wisconsin approved Isolation Request form and a satisfactory farm wiring inspection report which has been issued by a state certified commercial electrical inspector or a state certified master electrician. Subsequent to July 16, 1996, the utilities shall perform the investigation and separation within 30 days of the receipt of the above-referenced documentation. The utility shall not be required to initiate the neutral separation work requested prior to receipt by the utility of full payment for all costs associated with the neutral separation, as specified in (7.) above.

(14.) The utility may not install, or permit the continued use of, an isolator(s) at locations where livestock are not and/or no longer will be housed.

(15.) The company may supply service at one point to a customer for distribution by the customer to a number of buildings owned by the customer, provided that such buildings are located on contiguous properties including those directly across public thoroughfares.

Kaukauna Utilities
SCHEDULE OF DEPRECIATION RATES
TEST YEAR ENDED DECEMBER 31, 2025

Account	Description	Depreciation Rate
INTANGIBLE PLANT		
302	Franchises & Consents	2.00%
PRODUCTION PLANT - Hydraulic Production		
331	Structures and Improvements	4.00%
332	Reservoirs, Dams, & Waterways	3.00%
333	Water Wheels, Turbines, & Generators	2.10%
334	Accessory Electric Equipment	3.00%
335	Misc. Power Plant Equipment	3.30%
336	Roads, Railroads & Bridges	2.00%
PRODUCTION PLANT - Other Production		
341	Structures and Improvements	3.00%
342	Fuel Holders, Producers, & Access's	3.50%
343	Prime Movers	3.50%
344	Generators	3.50%
345	Accessory Electric Equipment	3.50%
346	Misc. Power Plant Equipment	3.30%
DISTRIBUTION PLANT		
361	Structures and Improvements	3.00%
362	Station Equipment	3.20%
364	Poles, Towers and Fixtures	3.90%
365	Overhead Conductors & Devices	3.10%
366	Underground Conduit	2.00%
367	Underground Conductors & Devices	3.30%
368	Line Transformers	3.30%
369	Services	4.10%
370	Meters	5.00%
371	Installations on Customer Premises	5.60%
373	Street Lighting & Signal Systems	5.10%
GENERAL PLANT		
390	Structures and Improvements	2.56%
391	Office Furniture & Supplies	6.25%
391.1	Computer Equipment	20.00%
392	Transportation Equipment	10.00%
393	Stores Equipment	5.00%
394	Tool, Shop & Garage Equipment	6.67%
395	Laboratory Equipment	5.00%
396	Power Operated Equipment	10.00%
397	Communications Equipment	10.00%
397.1	SCADA Equipment	10.00%
398	Misc. Equipment	6.67%