

BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Joint Application of Wisconsin Electric Power Company
and Wisconsin Gas LLC for Authority to Adjust Electric,
Natural Gas and Steam Rates—Test Year 2020

Docket No. 5-UR-109

DIRECT TESTIMONY OF RONDA L. FERGUSON

1 **Q. Please state your name, address, and title.**

2 A. My name is Ronda L. Ferguson. My office address is P.O. Box 19001, Green Bay,
3 Wisconsin 54307-9001. I am employed by WEC Business Services, serving all of the
4 WEC Energy Group utilities, including Wisconsin Electric Power Company
5 (“WEPCO”) and Wisconsin Public Service Corporation (“WPSC”) as the Manager of
6 Regulatory Compliance and Advocacy.

7 **Q. Please briefly describe your education, professional and utility background.**

8 A. I graduated from South Dakota School of Mines and Technology in 1992 with a
9 Bachelor of Science Degree in Mechanical Engineering. In 1992, I was employed by
10 WPSC in the Licensing and Systems Department for the Kewaunee Nuclear Power
11 Plant. I was in that position for three years. After being in the Gas Engineering area
12 for one year, I took the position of Rate Planner in 1996, Supervisor of Electric Retail
13 Pricing in 2005, and my current position of Manager of Regulatory Policy in 2012. In
14 that position, I am involved in rate-related engineering studies, rate development and
15 rate administration. Since the acquisition of Integrys Energy Group, Inc. by WEC
16 Energy Group my title has been Manager of Regulatory Compliance and Advocacy.

17 **Q. Have you testified before the Commission previously?**

18 A. Yes, I have testified before the Commission in a number of WPSC’s rate cases.

19 **Q. What is the purpose of your testimony?**

20 A. I describe WEPCO’s general approach to electric rate design and present WEPCO’s
21 proposed electric rate design for 2020 and 2021.

1 Specifically, I will address the following items related to electric rates and rules:

- 2 1. Proposed revenue allocation to rate classes;
- 3
- 4 2. Rate Design for Residential Customers, with a proposed 4.90%
- 5 annual rate increase for Rg-1 customers in 2020 and 2021;
- 6
- 7 3. Rate Design for Small Energy Only Commercial Customers, with
- 8 proposed annual rate decreases of 0.24% (2020) and 0.44% (2021)
- 9 for Cg-1 customers, and of 2.00% in both years for Cg-6 customers;
- 10
- 11 4. Rate Design for Medium and Large Demand Commercial Customers,
- 12 with proposed annual rate decreases of 1.66% (2020) and 1.01%
- 13 (2021) for Cg-2 customers, and proposed annual rate increases of
- 14 2.00% for Cg-3 customers in both years;
- 15
- 16 5. Rate Design for the Primary Classes, with proposed annual rate
- 17 increases of 3.13% (2020) and 1.97% (2021) for CP customers;
- 18
- 19 6. Customer-Owned Generation, including a proposed new fixed cost
- 20 recovery charge for CGS-NM and CGS-NP customers;
- 21
- 22 7. Lighting;
- 23
- 24 8. Energy for Tomorrow; and
- 25
- 26 9. Miscellaneous Tariff Changes.
- 27

28 **Rate Design Principles Utilized**

29 **Q. Please give an overview of the rate design philosophy reflected in WEPCO's**
30 **proposed electric rate design.**

31 A. Our basic philosophy is to implement James Bonbright's eight criteria of a desirable
32 rate structure. Mr. Bonbright is the author of the oft-cited "Principles of Public Utility
33 Rates." These criteria are:

- 34 1. Simplicity, understandability, public acceptability, and feasibility of
- 35 application.
- 36
- 37 2. Freedom from controversies as to proper interpretation.
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- 39 3. Effectiveness in yielding total revenue requirements.
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- 41 4. Revenue stability from year to year.
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- 43 5. Stability of the rates with a minimum of unexpected changes adverse
- 44 to existing customers.
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- 46 6. Fairness of the specific rates in the apportionment of total costs of
- 47 service among the different consumers.

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- 7. Avoidance of “undue discrimination” in rate relationships.
- 8. Efficiency of the rate design in discouraging wasteful use of service while promoting all justified types and amounts of use (consideration of energy conservation and load management).

Consistent with these criteria, WEPCO follows five general principles when developing rates:

- 1. A fully-allocated, embedded cost-of-service study should be used as a guide for determining revenue requirements for the individual rate schedules.
- 2. Both embedded and marginal costs should be used as guides in rate design.
- 3. Where increases or decreases would be substantial, based upon cost of service data, the change in rates should be moderated to incorporate reasonable rate stability.
- 4. Rate design should reflect cost of service to the extent practical.
- 5. Rate design should take into consideration the competitive impact on the continued viability of existing businesses, the ability to attract new businesses to the area, industry restructuring and evolution.

Q. How do these principles relate to WEPCO’s rate proposal in this case?

A. Consistent with these principles, WEPCO is seeking targeted two-year stepped overall electric rate increases of 2.9% effective in Test Year (“TY”) 2020 and 2.9% in 2021. The WEPCO Cost of Service Study (“COSS”) shows a wide variance in the cost to serve customer classes relative to current rates, from a 6.34% deficiency for residential customers to a 14.53% surplus collection in the lighting rate schedules. To temper increases to individual rate classes and promote stability, rate schedules that showed surplus collections were kept to no increases or slight decreases, whereas rate schedules that showed deficiencies were adjusted toward cost of service. WEPCO recognizes that if the electric revenue requirement changes significantly, these limits and the overall rate proposals may need to be revised.

1 **Description of Schedules**

2 **Q. Please describe the contents of Schedule 1 of Ex.-WEPCO WG-Ferguson-1.**

3 A. Schedule 1 summarizes current and proposed revenue by rate schedule, including
4 the proposed dollar and percentage changes for 2020 and 2021. Variances from the
5 income statement are noted on a reconciliation line item on the exhibit.

6 **Q. Please describe the contents of Schedule 2 of Ex.-WEPCO WG-Ferguson-1.**

7 A. Schedule 2 shows a summary of current and proposed revenue by rate schedule,
8 including the proposed dollar and percentage changes and proposed COSS results
9 for 2020 and 2021. The proposed rates recover WEPCO's forecasted revenue
10 requirement for 2020 and 2021, as presented by other witnesses. Present revenues
11 vary due to the adjustments noted on Schedule 1 of this Exhibit. WEPCO's proposed
12 revenues are close but not exactly equal to the filed revenue requirement forecast
13 because the revenue requirement is subject to change through the rate case process
14 and perfect precision is not required at this time.

15 **Q. Please describe the contents of Schedule 3 of Ex.-WEPCO WG-Ferguson-1.**

16 A. Schedule 3 shows the test year billing data by rate schedule, the current and
17 proposed revenue, as well as the dollar and percentage rate changes for 2020 and
18 2021. The percentage rate change for each rate schedule is the percentage change
19 for that billing unit. The proposed rates in this schedule reflect a fair and equitable
20 distribution of WEPCO's jurisdictional revenue requirement, taking into account all
21 pertinent factors.

22 **Q. Please describe Schedule 4 of Ex.-WEPCO WG-Ferguson-1.**

23 A. Schedule 4 shows typical monthly bills for various levels of consumption for the
24 residential rate schedule for 2020 and 2021. The first column (A) shows the monthly
25 consumption level; the next two columns (B and C) show the monthly and annual bills
26 under current rates for TY 2020; and the following two columns (D and E) show the
27 monthly and annual bills under proposed rates for TY 2020. The next two columns (F

1 and G) show the total dollar and percentage change in bills. The next two columns (H
2 and I) show the same proposed monthly and annual bills for 2021 followed by the
3 percent and monthly changes from 2020 to 2021 (J and K).

4 **Q. Please describe Schedule 5 of Ex.-WEPCO WG-Ferguson-1.**

5 A. Schedule 5 provides the same detail as Schedule 2, but for the small commercial and
6 industrial customer classes.

7 **Q. Please describe Schedule 6 of Ex.-WEPCO WG-Ferguson-1.**

8 A. Schedule 6 provides the same detail as Schedule 2, but for the medium Cg-2
9 commercial rate schedule.

10 **Q. Please describe Schedule 7 of Ex.-WEPCO WG-Ferguson-1.**

11 A. Schedule 7 shows the percentage increases applicable to the CP customers by
12 frequency with the proposed rate increases.

13 **Q. Please describe Schedule 8 of Ex.-WEPCO WG-Ferguson-1.**

14 A. Schedule 8 illustrates the derivation of Act 141 credits for the Large Energy
15 Customers as defined by 2005 Act 141.

16 **Q. Please describe Schedule 9 of Ex.-WEPCO WG-Ferguson-1.**

17 A. Schedule 9 shows the calculation of the embedded credit allowances.

18 **Q. Please describe Schedule 10 of Ex.-WEPCO WG-Ferguson-1.**

19 A. Schedule 10 calculates the fixed distribution costs not collected in the customer's
20 facilities charges for energy-only rate schedules.

21 **Q. Please describe Schedule 11 of Ex.-WEPCO WG-Ferguson-1.**

22 A. Schedule 11 contains new or redlined tariff changes.

23 **Q. Please describe Schedules 12 through 15 of Ex.-WEPCO WG-Ferguson-1.**

24 A. These schedules all relate to steam rates, and I will describe them in greater detail
25 later in my testimony.

26

1 **Revenue Allocation**

2 **Q. Please provide a general overview of how WEPCO groups the different rate**
3 **schedules for purposes of rate making.**

4 A. WEPCO's rate schedules are divided into groups based on historical rate design and
5 COSS groupings. For example, the secondary rates have six COSS groupings. One
6 of these groups contains the Rg-1 (residential) and Fg-1 (farm) rate schedules. The
7 facilities and energy rates for these rate schedules are set at the same levels but the
8 rate increases vary due to the load factors of each rate schedule. The medium
9 commercial customer group contains the Cg-3, Cg-3C (curtailable) and Cg-3S
10 (seasonal) rate schedules. The energy and demand rates are set at the same levels
11 for these rate schedules; only the facility and curtailable credits differ. The primary
12 group contains the CP and market-based rates. The Cp-1 and Cp-3 rate schedules
13 (Cp-3, Cp-3C, Cp-3S) have similar energy and demand rate levels. They also offer
14 different curtailable credits. The lighting and miscellaneous group contains lighting,
15 sirens and telecom equipment services.

16 **Q. Please provide a general overview of the COSS results.**

17 A. These results are shown in Ex.-WEPCO WG-Ferguson-1, Schedule 2. Residential
18 customers show revenue deficiencies ranging from -1.97% to 6.34% for TY 2020 and
19 from 2.88% to 3.64% in 2021. Small commercial customers show surplus collections
20 ranging from 8.28% to 3.79% for TY 2020 and revenue deficiencies between 2.76%
21 and 2.80% in 2021. The Cp rate schedules have combined revenue deficiencies of
22 3.84% in TY 2020 and 2.04% in 2021. The lighting and miscellaneous groupings
23 show a surplus collection of 14.53% in TY 2020 and a deficiency of 3.32% in 2021.

24 **Q. Is the Company proposing to set rates as proposed in the COSS results?**

25 A. The Company is proposing to move towards the COSS results while balancing other
26 rate design considerations, including stability and gradualism. For instance, our
27 proposed rate design is intended to avoid the fluctuations that would result for those

1 customer classes where COSS suggests a rate decrease in TY 2020 and an
2 increase in 2021. WEPCO's proposed rate design also avoids giving some rate
3 schedules large decreases and others large increases.

4 **Q. If the revenue requirement changes significantly due to the Staff audit, would**
5 **your proposed revenue allocation change?**

6 A. Yes. If that occurs, WEPCO will likely need to submit a revised rate design proposal
7 based on the Staff audit.

8 **Q. Please describe how the tax credit line item was calculated in rate design.**

9 A. The tax credit was allocated based on COSS groups on Ex.-WEPCO WG-Nelson-7.
10 Rate design used the total kilowatt-hours (kWh) in each group (as defined in COSS)
11 to credit the rate schedules on a \$/kWh basis.

12 **Q. Please describe the fuel adjustment line item in rate design.**

13 A. The current fuel credit is shown in present rates but all fuel cost recovery in the test
14 years are built into the base rates and therefore there is no fuel adjustment needed in
15 the proposed rates.

16 **Residential and Farm Rate Schedules**

17 **Q. Please describe the residential rate schedule.**

18 A. WEPCO has two residential rate options and one farm rate schedule:

19 Rg-1: Standard rate with a fixed charge and a flat volumetric energy charge.

20 This is the default rate for all residential customers.

21 Rg-2: Two-tier time-of-use (TOU) rate with fixed charge, on-peak energy and
22 off-peak energy. This is an optional rate.

23 Fg-1: This rate schedule mimics the Rg-1 rate schedule with the same rate
24 levels but is available to customers using electricity for farming
25 purposes.

26 Fixed charges are set at the same level for all residential, farm and small secondary
27 commercial rate schedules.

1 **Q. Please describe the overall increase for these rate schedules and how they**
 2 **relate to COSS.**

3 A. The proposed annual rate increases and COSS comparisons for the residential and
 4 farm rates are shown below.

Residential and Farm						
	COSS (Costs)			Proposed Rates (Revenues)		
Tariff	TY 2020	2021	Rev. Reqmt. 2021	TY 2020	2021	Rev. Reqmt. 2021
Rg-1 Fg-1	6.34%	3.64%	\$1,287,908,125	4.90% 5.14%	4.90% 4.90%	\$1,288,628,220
Rg-2	-1.97%	2.88%	\$30,975,715	0.55%	0.37%	\$30,979,758

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 7 To temper the rate increase to the Rg-1 and Fg-1 rate schedules, the proposed
 8 revenues take a step toward the COSS results but are less than what the COSS
 9 recommends. The Rg-2 rates have slight increases each year. This eliminates the
 10 fluctuation from a decrease in one year to a larger increase in the second year that
 11 would occur if the rates were set at the COSS levels in each year. The final proposed
 12 revenues for Rg-2 are very close to the COSS-proposed revenue requirement.

13 **Q. What facilities charge is WEPCO proposing for the residential and farm rate**
 14 **schedules?**

15 A. WEPCO is proposing to increase the facilities charge by a percentage equal to the
 16 overall proposed increase for the rate schedule, or 4.9% for each year. The daily rate
 17 will increase from \$0.52602/day to \$0.55180/day (\$16.83/month) in TY 2020 and
 18 \$0.57885/day (\$17.65/month) in 2021 for single phase customers, and to
 19 \$0.82770/day in TY 2020 and \$0.86828/day in 2021 for three phase customers.

20 **Q. How does this proposed rate increase compare to the customer-related**
 21 **charges shown in the WEPCO COSS?**

22 A. As explained in Mr. Nelson's testimony, plant and expenses are functionalized into
 23 Production, Transmission, and Distribution. These functions are classified as

1 Commodity (Energy), Demand (Capacity) and Customer-related costs.
2 The cost breakdowns for Rg-1 residential customers are shown on Schedule 31 of
3 Ex.-WEPCO WG-Nelson-7. The exhibit calculates the daily customer-related costs to
4 be \$0.64 per day (\$19.52 per month) for the Rg-1 and Fg-1 farm rates and \$0.71/day
5 (\$21.66 per month) for the residential TOU Rg-2 rate. Customer-related costs are
6 independent of the customer's consumption and are therefore fixed. The full cost of
7 service lines, metering, billing, and miscellaneous costs are included in customer
8 costs, as are a minimal portion of the secondary distribution lines, line transformers,
9 and the primary feeder system of poles, conduits and conductors. A breakdown of
10 the customer-related costs for Rg-1 is shown below.

Residential Customer-Related Costs – Single Phase	
Cost Category	\$/day
Distribution Overhead	\$0.23
Distribution Underground	\$0.08
Transformer – Customer classified	\$0.03
Service Lines	\$0.07
Metering	\$0.05
Billing	\$0.17
Total	\$0.64

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12 As further shown on Schedule 31, the customer-related costs for three phase
13 customers are a little more than double those of single phase customers. Prior to
14 2015, the three phase facilities charges were double the single phase facilities
15 charges. In Docket 05-UR-107, for TY 2015, the single phase and three phase
16 facilities charges were set at the same level. The Company proposes to reinstate a
17 differential between the single phase and three phase facilities charges by increasing
18 the three phase facilities charge by a factor of 1.5. This is a step toward the COSS-
19 recommended value and WEPCO may revisit the issue in future rate case
20 proceedings to move this charge closer to that value.

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1 **Energy-Only Small Commercial Rate Schedules**

2 **Q. Please describe the standard small commercial energy-only rate schedules.**

3 A. WEPCO has the following small commercial energy-only rate schedules:

4 Cg-1: Standard rate with fixed charge and a flat energy charge. This is the
 5 default rate for commercial customers with monthly consumption of
 6 less than 329 kWh/day or approximately 10,000 kWh per month. The
 7 TSSM and TSSU rate schedules, available for auxiliary power at
 8 substation rates, are also tied to the Cg-1 rate levels.

9 Cg-6: Two-tier TOU rate with facilities charge, on-peak energy and off-peak
 10 energy. This optional rate is available to commercial customers with
 11 monthly consumption less than 329 kWh/day or 10,000 kWh/month.

12 **Q. What rate levels is WEPCO proposing for Cg-1 and Cg-6?**

13 A. WEPCO's COSS indicates that these rate schedules should see a decrease in TY
 14 2020 and an increase in 2021. As explained above, to avoid annual fluctuation and
 15 help temper increases to other rate schedules, the proposed rate design takes a step
 16 toward COSS but still shows an overall surplus collection.

17 **Q. Please describe the overall decrease for these rate schedules and how they
 18 relate to COSS.**

19 A. The proposed annual rate reductions and COSS comparisons for the commercial
 20 energy-only rates are shown below.

Commercial Energy Only Cg-1 and Cg-6						
	COSS (Costs)			Proposed Rates (Revenues)		
Tariff	TY2020	2021	Rev. Reqmt. 2021	TY2020	2021	Rev. Reqmt. 2021
Cg-1	-3.79%	2.97%	\$236,758,007	-0.24 %	-0.44 %	\$237,071,604
Cg-6	-8.28%	2.77%	\$15,895,245	-2.00 %	-2.00 %	\$16,154,964

*Cg-1 includes Energy for Tomorrow for small commercial customers and TSSM & TSSU.

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1 **Q. What facilities charges is WEPCO proposing for these rate schedules?**

2 A. The facilities charges for Cg-1 and Cg-6 are currently set at the same level as the
3 residential and farm rate levels. The Company is proposing to maintain these
4 relationships, meaning the Cg-1 and Cg-6 facilities charges would increase by 4.9%.

5 **Q. What is WEPCO proposing for the energy charges for the Cg-6 rate schedule?**

6 A. The Company is proposing to maintain the current differential between the on-peak
7 and off-peak energy charges that was set in the last case. The energy rates decrease
8 by approximately 5% in 2021.

9 **Medium Secondary Demand – Cg-2**

10 **Q. What changes does WEPCO propose to the fixed and customer demand
11 charges intended to recover the costs of providing distribution service?**

12 A. WEPCO is proposing to increase the monthly fixed charge from \$34.34
13 (\$1.12590/day) to \$36.60 (\$1.200/day) in TY 2020 and \$41.48 (\$1.3600/day) in 2021.
14 This sets the fixed charge closer to the COSS-supported amount, as shown on
15 Schedule 30 of Ex.-WEPCO WG-Nelson-7. In Docket 05-UR-107, the Company
16 added a \$0/kW customer demand charge to the tariff so that customers could get
17 used to seeing their demands on their bills. As previewed in Mr. Rogers' direct
18 testimony in that docket, the Company is now proposing to phase in the customer
19 demand charge. Specifically, the Company is proposing to implement a customer
20 demand charge of \$2.00/kW in 2021. The Company proposes to postpone this
21 charge until then to prevent having to bill it in 2020 as the current billing system is
22 being retired. These rate levels are forecasted to produce \$16,359,401 of revenue,
23 approximately 47% of the COSS allocation of \$34,730,891 of distribution-related
24 costs shown on Schedule 30 of Ex.-WEPCO WG-Nelson-7.

25 **Q. What generation charges does WEPCO propose for this customer class?**

26 A. WEPCO proposes that generation and transmission costs for Cg-2 customers be
27 collected through a combination of on-peak demand charges and on-peak and off-

1 peak energy charges. Due to under-collection of the distribution costs in the facilities
2 and customer demand charges, WEPCO must collect the remaining distribution
3 costs in the on-peak demand and energy charges. WEPCO is proposing to maintain
4 the current energy and demand rates for TY 2020 and to decrease the on-peak and
5 off-peak energy charges for 2021. As shown on Schedule 30 of Ex.-WEPCO WG-
6 Nelson-7, WEPCO should be collecting \$152,745,626 through a combination of the
7 on-peak demand and on-peak and off-peak energy charges. With the increase in
8 distribution charges and a 10.89% decrease in energy charges, WEPCO is taking a
9 step toward COSS, and will continue to work towards COSS in future rate cases.

10 **Q. What is the overall impact of these changes on the Cg-2 customer class?**

11 A. The proposed rate design reflects a 1.66% decrease for TY 2020 and a 1.01%
12 decrease for 2021, compared to the COSS allocation of -5.55% for TY 2020 and
13 +2.57% for 2021. The proposed revenue collection for 2021 is \$187,251,703, which
14 is close to the final COSS revenue requirement of \$186,629,373 for that year.

15 **Q. With this rate design, including the added customer demand charge, what is
16 the projected impact on the individual customers in the Cg-2 customer class?**

17 A. The individual impacts for 2021 are shown on Schedule 6 of Ex.-WEPCO WG-
18 Ferguson-1 based on historical 2018 billing data. Out of the 7,623 customers for
19 whom we have 12 months of data in 2018, 98% of them will see a small bill increase
20 (4% or less). Of the remaining 126 customers who will see an increase of more than
21 4%, the vast majority (119) have zero consumption on their meter.

22 **Large Secondary Demand – Cg-3 Rate Schedules**

23 **Q. Please describe the large secondary rate schedules.**

24 A. Large secondary customers take service under three Cg-3 rate schedules: Cg-3, Cg-
25 3C (curtailable) and Cg-3S (seasonal):

26 Cg-3: Available to customers that use at least 986 kWh per day or
27 approximately 30,000 kWh per month. The rate schedule consists of a

1 facilities charge, customer demand, on-peak demand and on-peak
2 and off-peak energy rates.

3 Cg-3C: This curtailable rate is closed to new customers. The facilities charges
4 are higher than the standard Cg-3 but the energy and demand
5 charges mimic the Cg-3 rate. This rate has a curtailable credit of
6 \$0.02080/kWh. The customer is responsible for reducing load during a
7 curtailable event.

8 Cg-3S: This seasonal curtailable rate also is closed to new customers. The
9 facilities charge is the same as the Cg-3C rate and the demand and
10 energy rates are equal to the standard Cg-3 rate. It offers a \$2.00/kW
11 curtailable credit from April to September, when the customer is
12 responsible for reducing load during an event.

13 **Q. What changes does WEPCO propose to the Cg-3 fixed and customer demand**
14 **charges intended to recover the costs of providing distribution service?**

15 A. WEPCO's proposed facility and customer demand charges are shown in the
16 following tables:

Large Secondary (Cg-3) Facilities Charges					
Tariff	COSS (Costs)		Proposed Rates (Revenues)		
	Charge	Rev. Reqmt. 2021	TY 2020	2021	Rev. Reqmt. 2021
Cg-3	\$4.35/day*	\$9,916,943*	\$1.50/day	\$2.00/day	\$4,516,094
Cg-3C Cg-3S	*	*	\$3.65/day	\$3.75/day	\$43,921
Extra Meter	\$0.30/day	Included above	\$0.20/day	\$0.25/day	\$313,808
Total					\$4,873,822

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*The Cg-3, Cg-3C and Cg-3S rate schedules are combined in the COSS.

Large Secondary (Cg-3) Customer Demand Charges					
Tariff	COSS (Costs)		Proposed Rates (Revenues)		
	Charge	Rev. Reqmt. 2021	TY 2020	2021	Rev. Reqmt. 2021
Cg-3	\$4.17KW*	\$61,689,681*	\$2.50/KW	\$2.55/kW	\$46,842,775
Cg-3C Cg-3S	*	*	\$2.50/KW	\$2.55/kW	\$394,738
Total	\$47,237,513				

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*The Cg-3, Cg-3C and Cg-3S rate schedules are combined in the COSS.

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These rate levels are forecasted to produce \$52,111,336 of revenue in 2021, approximately 73% of the COSS allocation of \$71,606,624 of distribution-related costs shown on Schedule 30 of Ex.-WEPCO WG-Nelson-7.

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6 **Q. What generation charges does WEPCO propose for this customer class?**

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A. Similar to the Cg-2 rate schedule, WEPCO proposes that the generation and transmission costs for Cg-3 customers be collected through a combination of on-peak demand charges and on-peak and off-peak energy charges. For TY 2020, WEPCO is proposing a slight increase in the demand charges and a slight decrease in the energy charges. For 2021, WEPCO is proposing to maintain the TY 2020 on-peak demand charge and to further decrease the on-peak and off-peak energy charges.

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14 **Q. What is the overall impact of these changes on the Cg-3 customer class?**

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A. The proposed rate design reflects an approximate 2% increase for each of the Cg-3 tariffs for each of the test years, compared to the COSS-based increase of 2.10% for TY 2020 and 2.30% for 2021. The proposed revenue collection for 2021 is \$621,493,464, nearly identical to the 2021 COSS revenue requirement of \$621,478,205 for the combined Cg-3 rate schedules.

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1 **CP Rate Schedules**

2 **Q. Please describe the CP rate class.**

3 A. The CP rate class includes commercial and industrial customers served at primary
4 voltages of 3,180 volts or higher. CP customers' rates are classified as low (less than
5 12,470 volts), medium (between 12,470 and 138,000 volts) and high (more than
6 138,000 volts). The primary customer class in COSS includes Cp-1, Cp-3, Cp-3S,
7 Cp-FN and market-based rates.

8 **Q. Please describe the energy rates for the CP rate classes.**

9 A. Historically, the energy rates have been set at the same level for all the CP rate
10 schedules. In Docket 05-UR-107, Order Point 30 directed WEPCO to work with
11 WIEG, other interested stakeholders, and Commission staff to evaluate electric cost
12 of service with respect to the seasonality of its costs, and to develop and submit a
13 seasonally differentiated electric rate design proposal in its next base rate case.

14 **Q. What has WEPCO done to comply with Order Point 30?**

15 A. WEPCO worked with WIEG to develop summer/non-summer demand and energy
16 ratios for the Company's proposed rate design.

17 As a first step, WIEG and the Company agreed to introduce these seasonal rate
18 differentials for the Cp-1 Primary TOU rate and, in the interest of gradualism and to
19 avoid rate shock, to phase seasonal differentials into other tariffs over time. Because
20 the evaluation was done prior to this rate case, the cost of service study from Docket
21 05-UR-107 was used for the analysis during those discussions.

22 **Q. How did WEPCO address seasonal relationships for energy charges?**

23 A. WEPCO and WIEG agreed to use LMP relationships to differentiate on-peak summer
24 and non-summer energy rates. Historical summer on-peak to non-summer on-peak
25 ratios, based on on-peak hours for the CP Primary TOU hours and the MISO real
26 time LMPs at the WEC.S load node, are shown below.

Historical On-Peak Ratios (Summer to Non-Summer)			
Years	Avg. Summer LMPs	Avg. Non-Summer LMPs	Ratio
2014	41.21	47.13	0.87
2015	31.82	29.27	1.09
2016	36.19	28.51	1.27
2017	38.70	30.53	1.27
2018	38.58	33.21	1.16
5 Year Avg. (2014-2018)	37.30	33.73	1.11
4 Year Avg. (2015-2018)	36.32	30.38	1.20
3 Year Avg. (2016-2018)	37.82	30.75	1.23
2 Year Avg. (2017-2018)	38.64	31.87	1.21

*Based on WEC.S Real Time LMPs and CP Primary TOU Rate Hours

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3 **Q. What energy rate differential is WEPCO proposing for the Cp-1 Primary TOU**
4 **rate schedule?**

5 A. WEPCO is proposing a 15% differential for the seasonal energy rate for this tariff.
6 The actual ratio ranged from 0.87 to 1.27 in the last five years. A 15% differential will
7 be a first step toward a seasonal rate adjustment and can be revisited in the next rate
8 case.

9 **Q. What energy charges is WEPCO proposing for the CP rate schedules?**

10 A. Comparing current revenues to 2021 revenues, WEPCO is proposing an overall
11 decrease of approximately 7.8% for the on-peak energy charges and less than a 1%
12 increase to the off-peak charges. This results in an overall 3.5% decrease in revenue
13 collection from energy charges, which is a step toward COSS. The energy levels for
14 the Cp-1 Primary TOU rate schedule are differentiated by season, with the Cp-3, Cp-
15 3S, and Cp-FN rate schedules set at the same levels but on an annual basis.

16 **Q. How did WEPCO address seasonal relationships for demand charges?**

17 A. The Company presented WIEG with two scenarios. One scenario set the non-
18 summer demand charges at 20% of the current charge and another scenario set the
19 non-summer demand charges at 50% of the current charge, with both scenarios
20 maintaining the same level of demand revenues. To minimize bill impacts, WEPCO

1 accepted WEIG's recommendation to set the non-summer rates at approximately
2 88% of the current demand charge, which results in a summer to non-summer ratio
3 of 139%. This differential is close to WEPCO's summer/non-summer system peak
4 load differentials. WEPCO is a summer peaking utility with an average summer
5 system peak in 2018 of 5,344 MWs and a non-summer peak of 4,015 MWs.

6 **Q. What changes is WEPCO proposing to the customer demand charge?**

7 A. The Company is proposing to increase this charge to \$2.50/kW in TY 2020 and to
8 \$2.75/kW in 2021. This compares to a COSS recommendation of \$3.27/kW. With
9 these adjustments, WEPCO will collect less than one percent more than the COSS-
10 recommended distribution charges.

11 **Q. Is WEPCO proposing any changes to the curtailable credits in Cp-3, Cp-3S or
12 Cp-FN?**

13 A. No. WEPCO is proposing to maintain these credit levels.

14 **Q. What is the overall impact of these changes on the CP primary rate schedules?**

15 A. The overall rate increase for the CP rate schedules is 3.13% for TY 2020 and 1.97%
16 for 2021. This rate increase results in final test year revenue of \$607,420,066
17 compared to the COSS-indicated revenue requirement of \$611,598,224.

18 **Customer-Owned Generation**

19
20 **Q. Please describe WEPCO's current customer-owned generation tariffs.**

21 A. The Company currently has twelve customer-owned generation tariffs. Eight of these
22 are closed to new customers, seven of which also have defined tariff or contract
23 expiration dates. These tariffs and their participation rates are shown on the following
24 page:

25

26

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28

Closed Customer-Owned Generation Tariffs					
Tariff	Load	No. of Customers	Tariff Expires	Generator Size	Buy-back Rate (\$/kWh)
CGS-1	Netted	37	12/31/2024	>20 kW	Average DA LMP
CGS-2	Netted	40	12/31/2024	≤20 kW	Retail Rate
CGS-3	Emergency Capacity Tariff	1	NA	≥300 kW	Varies
CGS-4	Netted	11	Last Contract Expires April 2022	Wind >20 kW, ≤100 kW	Retail Rate
CGS-5	Not Netted	6	Last Contract Expires April 2028	Biogas ≤2,000 kW	On Peak: \$0.1550 Off Peak: \$0.0614
CGS-6	Netted	335	12/31/2024	≤20 kW	Retail Rate
CGS-8	Netted	171	12/31/2024	≤20 kW	Flat Rate: \$0.04245 On Peak: \$0.04982 Off Peak: \$0.03849
CGS-PV	Not Netted	28	Last Contract Expires June 2022	Solar PV >1.5 kW, ≤100 kW	All kWh: \$0.225

DA = Day Ahead
LMP = Locational Marginal Price
Closed = Closed to new customers
Netted = Load netted with generation

1

2

The Company has four customer-owned generation tariffs open to new customers.

3

These tariffs are summarized on the following page:

Open Customer-Owned Generation Tariffs					
Tariff	Load	Metering	No. of Customers	Generator Size	Buy-back Rate (\$/kWh)
CGS-NM	Netted	Gen. Meter and Load Meter (Order Point 31 05-UR-107)	662	<300 kW	LMP Based
CGS DS-FP	Not Netted	Gen. Meter and Load Meter	2	<2,000 kW	LMP Based
CGS DS-VP	Not Netted	Gen. Meter and Load Meter	0	>2,000 kW, ≤15,000 kW	Average DA LMP
CGS-NP	Netted	Gen. Meter and Load Meter (Order Point 31 05-UR-107)	32	< 15,000 kW	Non-Purchase Tariff

*Customer counts as of December 31, 2018.

2

3

4 **Q. Please explain Order Point 31 from Docket 05-UR-107.**

5 A. Order Point 31 directed WEPCO to install meters capable of measuring the actual
6 output capacity, on an interval basis, of generating systems under CGS-NM and
7 CGS-NP. WEPCO was ordered to bear the cost of the new meters.

8 **Q. How did the Company address Order Point 31?**

9 A. The Company installed interval meters on newly enrolled CGS-NM and CGS-NP
10 generators, with one exception. In October of 2016, the Company received a waiver
11 from the Commission for situations that required more than three meters to isolate
12 the generator output (PSC REF # 292776).

13

14

1 **Q. Please explain Order Point 32 from Docket 05-UR-107.**

2 A. Order Point 32 directed WEPCO to perform a true-up at the end of 2016 to address
3 any difference between the metered monthly maximum generation capacity of
4 customers enrolled under CGS-NM or CGS-NP and the rated nameplate capacity of
5 their systems. The Commission ordered this analysis because the demand charge
6 approved for these tariffs in the same docket was based on rated nameplate capacity
7 and some argued this was an inappropriate proxy for the actual amount of energy a
8 customer generates.

9 **Q. How did the Company address Order Point 32?**

10 A. Because the demand charge that was approved for the CGS-NM and CGS-NP tariffs
11 was overturned on appeal, the true-up was no longer necessary. However, as I
12 discuss next, we still collected the data that would have been necessary for the true-
13 up.

14 **Q. Please describe Order Point 33 from Docket 05-UR-107.**

15 A. Order Point 33 directed WEPCO to present the data collected by demand meters in
16 its next full rate case so the Commission could evaluate whether the COGS capacity
17 demand charges approved in that docket, and the basis for determining the billing
18 units for those charges, were appropriate or required modification. Based in part on
19 these data, WEPCO now proposes a somewhat different approach to the same end:
20 a modest step toward ensuring that generation-owning customers contribute their fair
21 share towards the fixed costs of connecting them to WEPCO's distribution system
22 and providing them with service up to their peak load whenever they need it. I will
23 discuss this proposal in greater detail after presenting the data we gathered.

24 **Q. Please describe the types and number of customers subject to Order Point 33.**

25 A. The population of relevant customers is summarized in the table on the following
26 page. The customer counts in each column represent new additions in that year.

27

	Total Interval Metered CGS-NM and CGS-NP Customers			
Rate Description	2015	2016	2017	2018
Residential Standard	62	118	139	203
Residential Time of Use	14	17	18	17
Commercial Non-Demand	8	3	10	12
Commercial Demand	5	15	11	10
Total	89	153	178	242

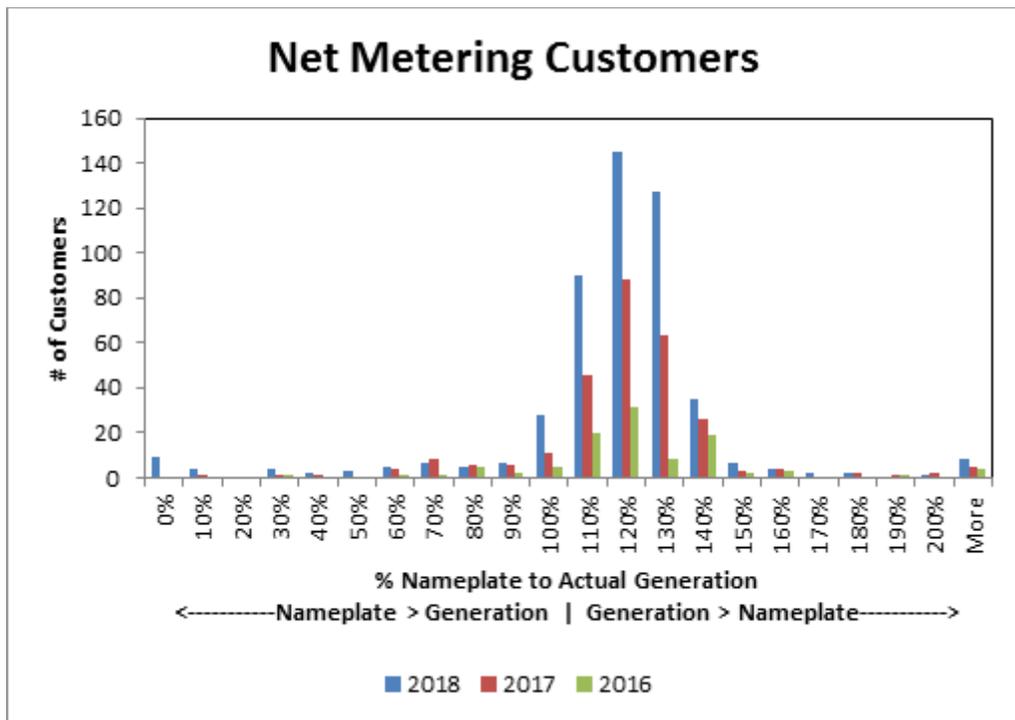
1 *Includes customers that had 365 days of consumption for each specific year.

2 **Q. Please describe the customer interval data and how it compares to generator**
3 **nameplate capacity ratings.**

4 A. The installed generation on the CGS-NM tariff is all solar generation. A direct
5 comparison between nameplate capacity and actual generation is not possible
6 because the nameplate capacity of the solar generation is stated in direct current
7 (DC) and the generator output from the customer's inverter is measured in alternating
8 current (AC). To compare the generator output to the generator nameplate capacity,
9 we converted the DC rating to AC by applying an inverter efficiency factor of 0.77, an
10 average calculated by the National Renewable Energy Laboratory and specified in
11 the CGS-NM tariff.

12 **Q. How does actual peak demand in AC compare to the generator nameplate**
13 **capacity converted to AC?**

14 A. The majority of the generators we measured produced between 100% and 150% of
15 their nameplate capacity. Below is a graph that illustrates the results by year. In this
16 graph, if the percentages are lower than 100%, the generator produced less than the
17 nameplate capacity. If the percentages are greater than 100%, the generator
18 produced more than the nameplate capacity. For example, in 2018, 145 customers
19 had generators that produced between 110% and 120% of the generator nameplate
20 capacity, when converted to AC.



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Q. Is there a more appropriate factor for converting the generator nameplate (DC) to the generator output (AC)?

A. Potentially, but with our enhanced ability to measure generator output, it would be more reasonable to base fixed cost recovery on actual metered output going forward. Customers could achieve better efficiency than the 77% inverter efficiency factor we assumed by investing in a higher efficiency inverter, using battery storage, or aligning generation with consumption. Because of the multiple contributors to the range of the generator’s measured output, and because we are now able to directly measure customer-specific generator output, the Company is recommending that the actual measured generation output be used to assess charges intended to recover fixed costs of service.

1 **Q. Is Wisconsin Electric proposing any changes to its net metering tariffs?**

2 A. Yes. The Company continues to pursue net metering rates that more closely follow
3 the fundamental principle of cost causation: that customers should pay approximately
4 what it costs the utility to serve them. This year, we are proposing a new charge for
5 our two open net metering tariffs, CGS-NM and CGS-NP, to better align rates with
6 costs. Our proposed Fixed Cost Recovery Charge ("FCRC") is designed to recover a
7 small portion of the fixed costs CGS customers avoid paying when they generate
8 their own power. Because WEPCO currently collects a substantial portion of its fixed
9 cost of serving smaller customers through its volumetric energy rates, customers who
10 generate their own energy avoid paying some of these fixed costs. The proposed
11 FCRC takes a modest correctional step by recovering a portion of these costs
12 through a charge based on the customer's average monthly peak generation.

13 **Q. How is CGS-NM structured currently?**

14 A. CGS-NM is a voluntary net metering tariff that allows customers not only to offset
15 their electricity consumption with their own generation, but also to sell excess
16 generation back to the Company at a buy-back rate based on locational marginal
17 prices (LMPs). Customers taking service under this tariff have two meters: one for
18 generation (which measures the energy the customer produces) and one for load
19 (which measures the energy the customer uses). The tariff is limited to customer-
20 owned generators smaller than 300 kW, and 662 customers were on the tariff as of
21 December 31, 2018.

22 **Q. What types of customers take service under the CGS-NM tariff?**

23 A. Most of our CGS-NM customers are residential customers who would otherwise take
24 service under Rg-1, our standard energy-only residential tariff, with smaller
25 generation systems (typically under 20 kW). But a number of our CGS-NM customers
26 fall into the commercial class, with larger generation systems (up to the 300 kW tariff
27 limit), and would otherwise take service under one of our demand and energy tariffs.

1 There are exceptions; for example, some residential customers may have larger
 2 generation systems, and some commercial customers may take service under an
 3 energy-only rate. The table below shows the breakout of CGS-NM generation
 4 capacity by customer type. For present purposes, I will distinguish between CGS-NM
 5 customers on an energy-only rate (the first three rows of the table) and CGS-NM
 6 customers whose tariff includes a demand charge (the last row of the table). Our
 7 proposed FCRC would apply to the first group; for the second group, we propose a
 8 new standby charge that I will discuss later.

CGS-NM Customer Generation Capacity						
Customer Type	Generation Capacity (kW)					
	<10	10 - 19	20 – 29	30 - 39	40 - 49	>50
Residential & Farm Flat (Rg-1, Fg-1)	468	47	3	1	0	3
Residential TOU (Rg-2)	55	11	0	0	0	0
Commercial Energy Only	14	8	2	3	2	4
Commercial Demand & Energy	1	1	2	1	2	34

9

10 **Q. How are current rates structured for CGS-NM customers on energy-only rates?**

11 A. Under the current rates, these customers purchase any net energy they use at the
 12 volumetric retail rate applicable to their class (again, for ordinary residential
 13 customers, Rg-1). They also pay the same monthly facilities charge as other
 14 customers in their class. However, unlike the other customers in their class, they do
 15 not pay all of the fixed costs that the utility incurs to provide them a reliable energy
 16 infrastructure whenever they need it—24 hours a day, 7 days a week, 365 days a
 17 year—to purchase energy from the utility or sell energy they generate to the utility.

18 **Q. Why is that?**

19 A. This is a result of WEPCO's current, traditional electric rate design for smaller
 20 customers. Because the Company's volumetric energy rates recover a large portion
 21 of the Company's fixed costs of service, customers who offset a portion of their load

1 with their own generation avoid paying some of the fixed costs that the Company
2 incurs to serve them. For example, if a customer offsets all of their load with their own
3 generation, their bill can be just the fixed monthly facilities charge. They wouldn't pay
4 any energy charges because they have offset all of their load with generation,
5 avoiding (but not reducing) all the fixed costs that are recovered in the energy rate.

6 **Q. Do you have data on the cost to serve customers who own generation?**

7 A. Yes. Like any public utility, WEPCO has the important obligation of providing a fully
8 functioning electric generation, transmission, and distribution system sized to meet
9 the peak demand of *all* of its customers, including those who own their own
10 generation, plus a reserve margin. We know what it costs to provide that system
11 because we complete very detailed cost and sales forecasts and a COSS as the
12 basis for our request to adjust electric rates. My colleague Aaron Nelson describes
13 WEPCO's COSS in his direct testimony.

14 **Q. Does the COSS provide information on the costs of serving each class of**
15 **customers?**

16 A. Yes. As Mr. Nelson explains, we use fairly complex, Commission-approved allocation
17 methodologies to ensure that our COSS appropriately apportions total costs of
18 service to the various customer classes (residential, industrial, commercial, and so
19 on) based on the principle of cost causation. Although competing policy
20 considerations may sometimes justify departing from basing rates purely on COSS,
21 our proposed rate design reflects our best effort to reasonably apportion costs to the
22 customers causing them, taking into account the various rate design factors I
23 identified at the beginning of my testimony.

24 **Q. What does the COSS tell us about the Company's fixed and variable costs?**

25 A. We know that the majority of the Company's costs of service are fixed, by which I
26 mean they are required to provide service to customers regardless of how much
27 energy they use. These include the costs of building and maintaining the utility's

1 infrastructure (power plants, transmission lines, substations, and distribution lines).
2 They also include a host of business-related costs, like labor, vehicles, insurance,
3 and the utility's billing, administrative, and customer services function—in layman's
4 terms, "overhead." A smaller portion of the Company's costs are variable, meaning
5 they increase or decrease with energy consumption. The primary example is the fuel
6 we use to power our non-renewable generation plants.

7 The relationship between fixed and variable costs is fairly lopsided. For example, our
8 COSS tells us that of all the costs to serve our residential customers, 78% are fixed
9 and only 22% are variable. While there may be room for debate about exactly what
10 proportion of overall costs are fixed, there can be little debate that the fixed costs of
11 providing residential and small commercial electric service are much greater than
12 currently reflected in the monthly facilities charge that these customers currently pay.

13 **Q. How do fixed and variable costs relate to customer rates?**

14 A. When we design rates, we have choices to make about how to recover our fixed and
15 variable costs. One way to do this would be to take all of our fixed costs, divide them
16 by our total number of customers, and have each customer pay an identical share of
17 our fixed costs. This would leave only our variable costs to be recovered through a
18 volumetric charge, *i.e.*, a charge based on how much energy each customer uses.
19 However, this would result in higher fixed monthly charges unrelated to energy use.
20 Historically, electric rates have been designed to recover a significant portion of the
21 utility's fixed costs through the volumetric charge in order to provide a stronger
22 incentive for customers to conserve their use of energy. Thus, in our tariffs for
23 residential and small commercial customers, the monthly facilities charge recovers
24 only *some* of our fixed costs, and the volumetric charge based on energy usage
25 recovers both our variable costs *and* the remaining fixed costs not recovered by the
26 monthly facilities charge.

27

1 **Q. How does this play out in the context of a specific tariff?**

2 A. I will use our primary residential tariff, Rg-1, as an example because most of our
3 CGS-NM customers are taking service under that tariff. If we were to set the Rg-1
4 facilities charge at the level necessary to capture all of our fixed costs, it would be
5 considerably higher than the \$17.65 per month proposed in this case. Because the
6 facilities charge recovers only a portion of our fixed costs, we need to recover all of
7 the remaining fixed costs through the volumetric energy charge, which still needs to
8 recover all of the Company's variable costs, as well.

9 **Q. What are the full costs of serving a standard residential customer per COSS?**

10 A. The fixed and variable costs are shown on Schedule 30 of Ex.-WEPCO WG-Nelson-
11 7. The costs are broken down on an energy basis on line 6. At lines 8-10, Mr.
12 Nelson's exhibit allocates these costs to the residential class and shows how they
13 would be recovered in rates if the Company had a more sophisticated rate design for
14 residential customers, similar to the rate design of a large industrial customer:

Rg-1 COSS Results			
Service Provided	Cost in \$/kWh (Line 6)	Appropriate Charge (Lines 8-10)	Type of Cost
Customer-Related	\$0.03160	\$0.64/day	Fixed
Distribution Demand	\$0.03033	\$7.74/kW	Fixed
Transmission Demand	\$0.01693	\$7.38/kW	Fixed
Transmission Energy	\$0.00030	\$0.00030/kWh	Variable
Production Demand	\$0.05636	\$24.57/kW	Fixed
Production Energy	\$0.03677	\$0.03677/kWh	Variable
Total	\$0.17229		

15 *\$/MWh converted to \$/kWh

16 **Q. How do these concepts relate to net metering customers?**

17 A. In most respects, customers on the CGS-NM tariff are just like any other customers in
18 their class. But for their ability to offset some of their consumption with onsite
19 generation (and, in some cases, deliver excess generation back to the grid), they

1 take service under the same tariff as their neighbors (again, typically Rg-1) whenever
2 they purchase energy from WEPCO, reflecting the fact that the same power grid (with
3 the same costs) exists to serve all of them.

4 However, CGS-NM customers are different from their neighbors in one key respect:
5 when they avoid purchasing energy by generating it themselves, they avoid paying
6 some of the fixed costs that their neighbors are paying as part of their energy rate.

7 For example, consider two neighbors, one with solar panels and one without, who
8 both consume 1,000 kWh of electricity in an average month. Although both rely
9 equally on the electric grid all month long for service up to their peak loads, and
10 although the utility must size its system to serve both of their peak loads, the solar
11 customer will not pay the same share of the fixed costs of that system as her
12 neighbor will. Instead, under WEPCO's proposed rates, if that customer generates
13 600 kWh of electricity in an average month, she will avoid not only our variable costs
14 of providing that energy to her (which is appropriate), but also 60% of the fixed costs
15 her neighbor is paying for the same system.

16 If these differences persist across an entire class of customers, the result will be that
17 the total difference needs to be made up somewhere. If and to the extent a portion of
18 WEPCO's residential CGS customers avoid contributing their share of the fixed costs
19 allocated to the customer class, the costs must be collected from the other, non-
20 generating customers in the class. Customers without their own generation will end
21 up subsidizing their CGS-NM neighbors.

22 **Q. Is Wisconsin Electric proposing the FCRC to address these issues?**

23 A. Yes, precisely. For energy-only customers with generation up to 300 kilowatts—the
24 majority on the CGS-NM tariff—we propose a new fixed cost recovery charge or
25 “FCRC” of \$3.53 per kilowatt of monthly peak generation to capture some of the fixed
26 costs these customers avoid paying when they self-generate.

27

1 **Q. How would the new FCRC proposed for CGS-NM customers work?**

2 A. In a given month, CGS-NM customers would continue to pay the same facilities
3 charge as their neighbors, as well as the same volumetric rate for the net energy they
4 consume. In addition, they would be subject to the FCRC, which would apply to the
5 actual monthly peak output of their generation system. The FCRC would commence
6 January 1, 2021 for CGS-NM customers.

7 **Q. What is your estimate of the average CGS-NM customer's generator output?**

8 A. Thanks to the meters installed pursuant to Order Point 31 in Docket 05-UR-107, the
9 Company has metered generation output data for customer generation installations
10 for every hour. Using data from the 440 customers that had 365 days of data in 2018,
11 we calculated the annual production from the customer generation. On average,
12 these customers generated 1,229 kWh per year for each kW of installed capacity.
13 This equates to an approximate 14% capacity factor for the CGS-NM customers. We
14 used these figures to derive the FCRC, as I will explain in greater detail in a moment.

15 **Q. Please explain what costs are included in the FCRC.**

16 A. The charge is designed to recover two cost components corresponding to the first
17 two rows of the table on page 27 of my testimony: (1) the customer-related
18 distribution costs that are not collected in the facilities charge and (2) the distribution
19 demand costs, both at a class-specific level as shown in the COSS. I will first walk
20 through how we used the COSS to calculate the costs to be recovered in the FCRC
21 for the residential and farm rate classes. After that, I will explain how we translated
22 these costs (\$/kWh) into the FCRC (\$/kW/month).

23 Step 1 - Calculate customer-related costs not recovered in the facilities charge:

24 The first step is to identify the total customer-related distribution costs that are
25 allocated to the Rg-1, Fg-1 and Rg-2 rate schedules. Because some of these costs
26 are recovered through the daily facilities charge that customers already pay, the
27 FCRC would include only the customer-related distribution costs that are *not* already

1 collected through the facilities charge. This difference is then divided by the
 2 forecasted annual energy consumption for these rate schedules:

3	Customer-Related Distribution Costs	
4	Rg-1, Fg-1 (COSS, Sched. 30, Col. I, line 4)	\$237,509,848
5	Rg-2 (COSS, Sched. 30, Col. I, line 12)	\$ 4,178,188
6	<u>Total</u>	<u>\$241,688,036</u>
7		
8	Facilities Charge Revenues in 2021 Proposed Rates	
9	Rg-1, Fg-1	\$213,769,804
10	Rg-2	\$ 3,427,650
11	<u>Total</u>	<u>\$217,197,454</u>
12		
13	Customer-Related Distribution Costs not Collected in Facilities Charge (\$)	
14	Customer-Related Distribution Costs	\$241,688,036
15	Facilities Charge Revenues in 2021 Proposed Rates	\$217,197,454
16	<u>Difference</u>	<u>\$ 24,490,582</u>
17		
18	Customer-Related Distribution Costs not Collected in Facilities Charge (\$/kWh)	
19	Customer-Related Distribution Costs not Collected (\$)	\$24,490,582
20	Rg-1, Fg-1, Rg-2 Energy (kWh)	7,741,019,654
21	Costs not recovered on a \$/kWh basis:	\$0.00316/kWh
22		

23 Step 2 – Calculate total distribution costs:

24 The second step is to calculate the total fixed distribution costs for the Rg-1, Fg-1,
 25 and Rg-2 rate schedules. This is done by isolating the distribution demand costs
 26 allocated to customers under those rate schedules and adding them to the customer-
 27 related distribution costs not collected in the fixed charge, on a \$/kWh basis.

28		
29	Distribution Demand Costs	
30	Rg-1, Fg-1 (COSS, Sched 30, Col H, line 4)	\$227,952,827
31	Rg-2 (COSS, Sched 30, Col H, line 12)	\$ 4,269,816
32	<u>Total Distribution Demand Costs</u>	<u>\$232,222,643</u>
33		
34	Distribution Demand Costs	
35	Total Distribution Demand Costs	\$232,222,643
36	Rg-1, Fg-1, Rg-2 Energy (kWh)	7,741,019,654
37	Costs not recovered on a \$/kWh basis:	\$0.03000/kWh
38		
39	Total Distribution Costs	
40	Remaining Customer-Related Distribution Costs	\$0.00316/kWh
41	<u>Distribution Demand Costs</u>	<u>\$0.03000/kWh</u>
42	Total Distribution Costs	\$0.03316/kWh
43		

44
 45
 46

1 **Q. Based on that calculation, what annual distribution costs would a customer**
2 **who installs a 1 kW solar generation system avoid paying under the**
3 **Company's proposed rates?**

4 A. As I have explained, an average customer with a 1 kW solar installation would
5 generate 1,229 kWh on an annual basis. Under the current net metering
6 methodology, this 1,229 kWh would be netted or subtracted from their consumption
7 assuming the consumption at the premises exceeded the solar generation each
8 month. Multiplying the \$0.03316/kWh of distribution costs that are being recovered in
9 the energy charge by the 1,229 kWh equals \$40.75 per year. This amount represents
10 the annual distribution costs avoided (but not reduced) by a net metering customer
11 with a 1 kW solar installation.

12 **Q. How does WEPCO propose to recover this \$40.75?**

13 A. One way would be to divide \$40.75 by 12 to derive a monthly amount and then bill
14 net metering customers this monthly amount times the nameplate capacity of their
15 generation system in kilowatts. As I have discussed, however, our new meters allow
16 us to treat customers on an individual basis, and the data we have already collected
17 shows that a customer's actual monthly generation may differ from nameplate
18 capacity in either direction. For these reasons, we are recommending that the FCRC
19 be assessed on the actual peak monthly output of the customer's generation system.
20 To do this, we first had to convert the \$40.75 in annual distribution costs into a per-
21 kilowatt charge that accounts for the relationship between nameplate capacity and
22 monthly peak generation.

23 **Q. How did you do that?**

24 Once again using data from our customer solar generation installations, we divided
25 total metered monthly peak generation by total nameplate capacity. This step of the
26 calculation recognizes that a 1 kW solar system does not generate a peak of 1 kW
27 every month, but something less in most months. The twelve monthly peaks would

1 therefore total less than 12 kW per year. The following table summarizes the monthly
2 peaks seen in our data, which add up to 11.55 kW of annual peak production.

3	January	0.831 kW
4	February	0.977 kW
5	March	1.075 kW
6	April	1.034 kW
7	May	1.045 kW
8	June	1.030 kW
9	July	1.026 kW
10	August	0.999 kW
11	September	0.992 kW
12	October	0.925 kW
13	November	0.837 kW
14	<u>December</u>	<u>0.779 kW</u>
15	Total	11.550 kW

16
17 **Q. How is the proposed \$3.53/kW/month FCRC calculated?**

18 A. To recover the \$40.75 of annual distribution costs that a customer with a 1 kW solar
19 generating system avoids paying in current rates, we divided \$40.75 (annual cost) by
20 11.55 kW (annual peak production) to arrive at the FCRC of \$3.53 per kilowatt of
21 monthly peak generation.

22 **Q. Have you calculated a specific FCRC for commercial energy-only customers?**

23 A. Yes. Using the same methodology as for the residential customers, the FCRC for
24 commercial energy-only customers equates to \$3.67/kW. This calculation uses an
25 average annual generation of 15,557 kWh, and an average system capacity of 13.99
26 kW. Thus, for each 1 kW of installed capacity, these customers would be generating
27 1,112 kWh. As shown on Schedule 10 of Ex.-WEPCO WG Ferguson-1, the
28 distribution costs not collected in the energy charge equate to \$0.02272/kWh or
29 \$25.26 per month. Dividing by the annual distribution demand of a 1 kW system (6.89
30 kW, per the peaking methodology explained previously for residential customers), the
31 FCRC for the commercial energy-only customer comes to \$3.67/kW.

32 **Q. Please illustrate what a theoretical residential customer with a 1 kW distributed
33 generation system would pay under the FCRC.**

34 A. The FCRC would only be assessed on the customer's actual, metered peak

1 generation each month, not the nameplate capacity of their system, so a year's worth
 2 of generation following typical peaks would result in the following charges:

3	Month	Peak Generation	FCRC	Monthly Charge
4	January	0.831 kW	\$3.53	\$2.93
5	February	0.977 kW	\$3.53	\$3.45
6	March	1.075 kW	\$3.53	\$3.79
7	April	1.034 kW	\$3.53	\$3.65
8	May	1.045 kW	\$3.53	\$3.69
9	June	1.030 kW	\$3.53	\$3.64
10	July	1.026 kW	\$3.53	\$3.62
11	August	0.999 kW	\$3.53	\$3.53
12	September	0.992 kW	\$3.53	\$3.50
13	October	0.925 kW	\$3.53	\$3.26
14	November	0.837 kW	\$3.53	\$2.95
15	December	0.779 kW	\$3.53	\$2.75
16	<u>Total</u>	<u>11.55 kW</u>		<u>\$40.76</u>

17
 18
 19 **Q. What is the average size of solar installations for the Rg-1, Fg-1 and Rg-2 rate**
 20 **schedule?**

21 A. Using the 2018 data from the 440 customers that had 365 days of data, the average
 22 size photovoltaic installation is 4.43 kW, with an average peak output of 4.25 kW.

23 **Q. Please provide a billing comparison for a typical solar customer taking service**
 24 **under the CGS-NM rate.**

25 A. The table below compares an average net metering customer with solar generation
 26 being billed (1) without any generation, (2) using the current netting methodology,
 27 and (3) with the proposed FCRC.

Example: Solar Generation Customer Bill							
Billing Charges		Solar Customer without Generation		Solar Customer with Generation (Current Netting)		Solar Customer with Generation (Current Netting + FCRC)	
Charge	Unit Charge	Billing Units	\$	Billing Units	\$	Billing Units	\$
Facilities	\$0.57885 / day	30 days	\$17.65	30 days	\$17.65	30 days	\$17.65
GFC	\$0.05951 / day	30 days	\$1.79	30 days	\$1.79	30 days	\$1.79
Energy	\$0.14406 / kWh	851 kWh	\$122.60	397 kWh	\$57.19	397 kWh	\$57.19
FCRC	\$3.53 / kW	N/A	N/A	N/A	N/A	4.25 kW	\$15.00
Total			\$142.04		\$76.63		\$91.63

1 As the chart indicates, the customer in this example will still realize a significant
2 savings from participating in net metering (\$50 per month), but will contribute slightly
3 more (\$15.00 per month) towards distribution costs than under current rates.

4 **Q. Have you attempted to verify that the Company's distribution costs to serve the**
5 **residential class are not reduced by customers with generation systems?**

6 A. Yes, our analysis shows that our costs of providing distribution service to a class do
7 not differ based on whether customers within that class own self-generation systems.

8 **Q. Why is that?**

9 A. WEPCO's distribution system is designed to meet its customers' peak demands.
10 From the data collected from residential customers with generation, we found that
11 these customers' average monthly peak demand was not reduced materially after
12 they installed generation:

13	Month	Peak kW	Peak kW
14		Consumption	Net
15	January	6.72	6.55
16	February	6.70	6.60
17	March	6.69	6.42
18	April	5.99	5.67
19	May	7.01	6.53
20	June	7.63	7.10
21	July	7.61	7.05
22	August	7.28	6.82
23	September	6.95	6.56
24	October	6.51	6.34
25	November	6.90	6.77
26	<u>December</u>	<u>6.95</u>	<u>6.84</u>
27	Average	6.91	6.60
28			

29 This is because customer-owned generation is intermittent, and the generation-
30 owning customer must still purchase 100% of their requirements from the utility when
31 their generation is not operating. For instance, on a hot summer day, solar panels
32 may reduce the customer's peak load during the day, but our system must be sized
33 to serve all of that customer's load once the sun goes down that night. In the table
34 below, we can see that the customer's metered peak monthly consumption (the
35 greatest load they place on the system that month) is virtually identical to the peak

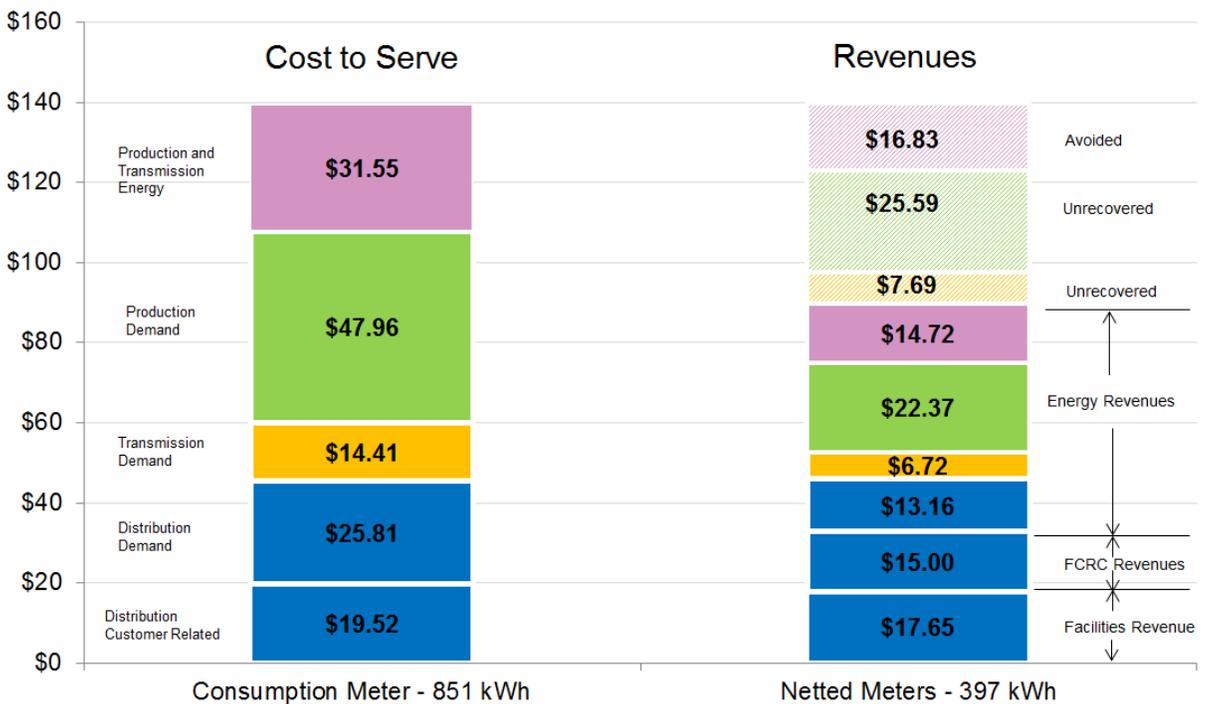
1 net of their load and generation in the same period. That is, regardless of any self-
 2 generation offset reflected in the second column, we still must size our distribution
 3 system to meet the peak load in the first column, and in any given month the two end
 4 up being roughly the same.

5 **Q. If implemented, will the FCRC ensure that Wisconsin Electric recovers all of its**
 6 **fixed costs from CGS-NM customers?**

7 A. No, not even close. As the figure below indicates, this charge is calculated to recover
 8 just one of several fixed cost components included in the volumetric energy charge
 9 and thus not recovered from net metering customers when they offset load. Again,
 10 based on our COSS, it would require significant monthly fixed charges to recover
 11 those costs fully on a fixed basis. By comparison, the FCRC we are proposing is
 12 relatively modest; in our view, it is a step towards appropriate rate-setting based on
 13 the principle of cost causation.

14

**Average Residential Net Metering Customer
 Cost of Service vs Revenues Collected**



15

16

1 **Q. What does this figure represent?**

2 A. The column on the left represents the full monthly cost of providing service to an Rg-
3 1 customer with an average consumption of 851 kWh per month. According to the
4 COSS for the 2020 test year, these costs total \$139.25. Broken out by functional
5 component, they are as follows:

6	Distribution customer-related costs		\$19.52
7	(Schedule 31, COSS)		
8	Distribution Demand	\$0.03033 * 851 kWh =	\$25.81
9	(Schedule 30, COSS)		
10	Transmission Demand	\$0.01693 * 851 kWh =	\$14.41
11	(Schedule 30, COSS)		
12	Production Demand	\$0.05636 * 851 kWh =	\$47.96
13	(Schedule 30, COSS)		
14	Production Energy	\$0.03677 * 851 kWh =	\$31.29
15	Transmission Energy	\$0.00030 * 851 kWh =	<u>\$00.26</u>
16	(Schedule 30, COSS)		\$31.55
17	Total Cost:		\$139.25

18
19 The column on the right represents the revenues that the average Rg-1 customer
20 with a 1 kW solar installation would pay to WEPCO under its proposed rates for
21 2021. These rate components include:

22	Facilities Revenue:	\$0.57885/day * 30.5 days	\$17.65 per month
23	Energy Revenue:	\$0.14406/kWh * 397 kWh	\$57.19 per month
24	FCRC Revenue:	\$3.53/kW * 4.25 kW peak generation	\$15.00 per month
25	Total Bill:		\$89.84 per month

26
27 Assuming net consumption of 397 kWh and self-generation of 454 kWh, these
28 revenue components may be correlated with the cost components above as follows:
29
30

Functional Cost	Revenue Type	Billing Unit	Charge	Total
Distribution	Facilities Charge	1 month	\$17.65 / month	\$17.65
Distribution	FCRC	4.25 kW	\$3.53 / kW	\$15.00
Distribution	Energy Rate	397 kWh	\$0.03316 / kWh	\$13.16
Transmission Demand	Energy Rate	397 kWh	\$0.01693 / kWh	\$6.72
Production Demand	Energy Rate	397 kWh	\$0.05636 / kWh	\$22.37
Prod. & Trans. Energy	Energy Rate	397 kWh	\$0.03707 / kWh	\$14.72
Transmission Demand	Unrecovered	454 kWh	\$0.01693 / kWh	\$7.69
Production Demand	Unrecovered	454 kWh	\$0.05636 / kWh	\$25.59
Prod. & Trans. Energy	Avoided	454 kWh	\$0.03707 / kWh	\$16.83

1

2 **Q. What does this comparison of costs and revenues illustrate?**

3 A. It shows that even after implementing the FCRC as proposed, the average Rg-1 solar
4 customer will pay approximately \$50 less per month than an identical customer
5 without generation, a savings of 11 cents per kWh of self-generated energy. The
6 savings are shown at the top of the column on the right, and are comprised of two
7 cost components:

8 Roughly a third of the amount (\$16.83) represents variable energy production and
9 transmission costs that the CGS customer arguably allows the utility to avoid by
10 purchasing less energy (“Avoided Energy Costs”). It is appropriate to credit these
11 savings to the CGS customer, and the customer receives that credit—and then
12 some—when we net their generation against their load.

13 The rest of the shortfall (\$33.28) represents fixed production costs (\$25.59) and
14 transmission costs (\$7.69) that this customer would *not* help the utility avoid, but will
15 avoid paying by avoiding the volumetric energy charge even after paying the
16 proposed FCRC (“Unrecovered Fixed Costs”). The Company has elected not to
17 address these costs at this time in the interest of gradualism in rate design. While
18 there is strong cost support for requiring CGS customers to pay most if not all of
19 these fixed costs, at this time we do not propose going beyond the FCRC.

1 **Q. How does the proposed FCRC relate to the CGS demand charge that WEPCO**
2 **proposed and the Commission approved in Docket 05-UR-107?**

3 A. The basic concept is the same; namely, the charge is intended to recover some of
4 the fixed costs that generation-owning customers avoid paying (but not causing)
5 when they avoid paying the utility’s volumetric energy charge. But there are several
6 differences that make the FCRC a superior method of accomplishing this modest
7 step.

8 First, we now have the benefit of both consumption and output data from the second
9 meters installed for customers who have installed solar generation. These data
10 provide a stronger factual basis for *designing* a fixed cost recovery charge by
11 confirming that customers who own solar generation systems have nearly identical
12 monthly peak demands as they did before their generation was installed. That is,
13 these customers place similar demands on the local distribution system with or
14 without their own generation. It is therefore reasonable to recover distribution costs
15 from them as we do from their non-generating neighbors in the same class.

16 A second difference is that the Company proposes to *bill* the FCRC using actual
17 meter data as opposed to nameplate capacity. Using metered data provides a more
18 accurate way to charge the FCRC to individual customers. As a result of this change,
19 if two customers have the same size generation system but one generates a lower
20 peak in a given month, she will pay a lower FCRC in recognition of the fact that she
21 contributed more to fixed costs than the customer who generated more.

22 Third, we have provided a transparent, step-by-step calculation of the FCRC,
23 showing exactly how it recovers class-specific costs identified in WEPCO’s COSS
24 through a charge based on metered data from customers with solar generation.

25

1 **Q. What do you propose for customers billed on demand rates that have their own**
2 **generation?**

3 A. For these customers, we are proposing that new customers pay a standby rate
4 similar to the one the Commission has approved for WPSC's distributed generation
5 customers. Based on the COSS submitted with Mr. Nelson's direct testimony, we will
6 discuss standby rate design options with these customers and file a proposed design
7 in supplemental testimony, with existing customers to be grandfathered through
8 December 31, 2028. This proposal is consistent with Order Point 34 from Docket 05-
9 UR-107, which directed Wisconsin Electric to develop a standby rate proposal with
10 affected customers and present that proposal in its next full rate case.

11 **Q. Does Wisconsin Electric propose changing the buyback methodology or**
12 **monthly netting period for CGS-NM?**

13 A. Not at this time. However, now that we have installed the new meters ordered by the
14 Commission, we have the ability to net CGS-NM customers' production and
15 consumption on an hourly basis, and may propose doing so in the future.

16 **Q. When does Wisconsin Electric propose phasing in these charges?**

17 A. To allow time for billing implementation, we would propose to delay the new CGS-NM
18 charges until January 1, 2021.

19 **Q. Is Wisconsin Electric proposing the same changes to its CGS-NP tariff?**

20 A. Yes. The only material difference between the CGS-NM and CGS-NP tariffs is the
21 absence of a buyback rate: customers on the CGS-NP (non-purchase) rate are not
22 compensated for their generation. These customers can still offset some or all of their
23 own load and avoid paying the fixed cost of distribution to that extent.

24 **Q. Are there other ways Wisconsin Electric could address the disconnect that**
25 **occurs when fixed costs are recovered in variable charges?**

26 A. Yes. To take one example, the Company could unbundle the energy rate for energy-
27 only rate schedules, with distribution-related costs charged separately for all

1 customers and not netted (that is, not credited) for net metering customers. This
2 approach was proposed by Commission Staff in Docket 05-UR-107.

3 **Q. What does unbundling mean and what are its benefits?**

4 A. Unbundling simply means separating the current volumetric energy rate into two
5 distinct charges that would be listed separately on customers' bills. Traditionally this
6 takes the form of a delivery charge and an energy charge. The delivery charge would
7 include customer- and distribution-related costs not covered in the facilities charge,
8 as well as transmission system costs. The energy charge would include costs to
9 produce the energy the customer uses.

10 Relative to current rates, non-generating customers would not pay any more or less
11 for energy under unbundled rates, as the sum of the new delivery and energy
12 charges would be designed to equal the former energy charge. But the new bill
13 structure would improve transparency, providing customers with better information
14 about how each component of their rate relates to the utility's costs of service. By the
15 same token, transparency around these cost components and their relationship to
16 rates would enhance understanding of any rate design changes the Company may
17 wish to pursue in future rate cases. Here, for example, instead of calculating the
18 FCRC as explained above, we could derive it directly from CGS-NM customers'
19 unbundled rates by only crediting the customer's energy charge for self-generated
20 energy and not crediting the delivery portion of their bill.

21 **Q. How would the proposed \$3.53/kW/month FCRC compare to a delivery charge
22 that would result from unbundling the energy rate?**

23 A. For the average customer, the two charges would be almost identical, assuming the
24 delivery charge were limited to the same unbundled distribution cost components. As
25 I described previously, the distribution-related costs recovered in the energy charge
26 for 2021 is \$0.03316/kWh. For the 440 CGS-NM customers for whom we have
27 complete 2018 data, the average solar output being netted is 454 kWh per month.

1 Multiplying these two figures yields a monthly charge of \$15.05, which is very close to
2 applying the \$3.53/kW/month FCRC to the average peak output of 4.25 kW (\$15.00).

3 **Q. Why does WEPCO prefer the FCRC to the unbundling alternative?**

4 A. Implementing an unbundled approach for all of WEPCO's rates, as other Wisconsin
5 utilities have done, would require it to change how it bills more than 1 million
6 accounts, as opposed to adding a single additional charge for those relatively few
7 customers (currently well under 1,000) who have opted to add self-generation and
8 take service on a net metering rate. Rather than requiring all of its customers to learn
9 a new rate design in order to understand their bills, WEPCO prefers the FCRC for its
10 CGS-NM customers, but is open to the unbundling alternative for the reasons I just
11 discussed. If the Commission prefers to pilot unbundling, it would be reasonable to
12 start with net metering customers.

13 **Residential Electric Vehicle Pilot**

14 **Q. What is Wisconsin Electric's proposal for an electric vehicle ("EV") pilot
15 program?**

16 A. Wisconsin Electric proposes a new pilot tariff, the Residential Electric Vehicle Pilot
17 ("REV Pilot"). The tariff will provide two principal benefits to customers.
18 First, it will allow residential customers to take advantage of time of use rates for
19 charging an electric vehicle at their home while having the remainder of their electric
20 usage billed according to their existing, underlying tariff.
21 Second, the proposed pilot will provide rebates of up to \$1,000 to residential
22 customers who install EV chargers at their homes. This rebate will offset the cost of
23 installing EV chargers and accelerate the pace of their adoption, allowing Wisconsin
24 Electric to study how EV charging will complement other grid-tied technologies, as
25 well as where it may cause challenges.

26 **Q. Which customers will be eligible for the REV Pilot?**

27 A. The pilot will be available to residential customers on the Rg1, Rg2, and Fg1 tariffs.

1 Customers must install a qualifying system to be eligible for the REV Pilot. Qualifying
2 systems are Level 2 systems operating at 240 volts that offer fast charging capability
3 and are Underwriters Laboratories or Electrical Testing Laboratories certified.
4 Customers must be in good standing (*i.e.*, they must have had no delinquent bills or
5 disconnections in the past twelve months). As explained in Mr. Stasik's testimony, the
6 rebates available under the REV Pilot will be capped at \$7.5 million annually.

7 **Q. How will customers take advantage of REV Pilot's rebate for EV chargers?**

8 A. Customers must sign up for the REV Pilot to be eligible for a rebate and provide
9 written evidence of EV ownership and installation of a qualifying system. Before they
10 undertake the expense of installing EV charging, customers will be able to confirm
11 with Wisconsin Electric's customer service department that rebates remain available
12 for the year. Rebate checks will be sent to customers after they provide the required
13 documentation and the Company has verified their eligibility for the tariff.

14 **Q. How will Wisconsin Electric bill customers on the REV Pilot?**

15 A. Customers will continue to take residential service on their underlying tariffs. The
16 REV Pilot will require participating customers to have Wisconsin Electric install a
17 second meter that will measure consumption for the EV charger only. The REV Pilot
18 will incorporate time-of-use ("TOU") billing for this second meter, which will
19 encourage customers to charge their vehicles overnight when system demand is
20 lower. The TOU rates incorporated in the REV Pilot will be the same as the rates
21 under Wisconsin Electric's existing Rg2 tariff. Customers may select as their On-
22 Peak period the 12-hour window beginning at 7:00 A.M., 8:00 A.M., 9:00 A.M., or
23 10:00 A.M. Customers will pay an extra meter charge of \$0.05951 per day to cover
24 the cost of the second meter. Customers will receive bills that reflect the electric
25 consumption at TOU rates for the EV charger, the balance of their electricity charges
26 at underlying rates, the facilities charges and the extra meter charge.

27

1 **Q. What does Wisconsin Electric expect to learn from offering the REV Pilot?**

2 A. As EVs become more common, Wisconsin Electric needs to understand at least
3 three potential effects their proliferation could have on generation and distribution
4 resources.

5 First, Wisconsin Electric anticipates that charging EVs during off-peak hours will
6 allow the utility to leverage generating and distribution capacity during periods when
7 they are not fully utilized. EV charging also has the potential to increase overall
8 electric consumption and to partially offset reductions in demand due to increasingly
9 energy efficient households. This will allow fixed generation and distribution costs to
10 be spread over more sales, thereby driving down rates for all customers, including
11 those who do not have EVs.

12 Second, increased EV charging should complement wind generation, which tends to
13 be greater at night. Thus, in the long run, increasing EV charging may improve the
14 economics of wind generation relative to other sources of energy.

15 Third, it will be important to understand how increased EV charging will affect load on
16 the distribution system, because a single EV can account for significant increased
17 electric consumption at a residence. While Wisconsin Electric anticipates that it will
18 be able to avoid material upgrades to the distribution system by implementing TOU
19 rates, it will be important to understand customer behavior so that future, larger-scale
20 deployments of EV charging technology maximize system savings without requiring
21 costly distribution upgrades.

22 Wisconsin Electric believes that the REV Pilot's rebate will help to accelerate
23 installation of at-home Level 2 chargers, thereby allowing the utility to understand the
24 full effect of EVs on the distribution system and resulting impacts on costs for all
25 customers.

26

27

1 **Q. What is the timing for REV Pilot’s implementation?**

2 A. Wisconsin Electric proposes to make the REV Pilot available to customers January 1,
3 2021, and to enroll customers on a first-come, first-served basis.

4 **Q. Is there precedent for this type of EV charging tariff?**

5 A. Yes. Other state commissions have authorized similar programs, including the
6 Michigan Public Service Commission, which recently approved tariffs for Consumers’
7 Energy and Detroit Edison. This Commission has also approved a similar tariff for
8 Madison Gas & Electric.

9 **Lighting**

10 **Q. Is WEPCO proposing any changes to its Lighting rate schedules?**

11 A. WEPCO is proposing to decrease lighting rates by 3.10% in TY 2020 and 1.31% in
12 2021 as shown on Ex.-WEPCO WG-Ferguson-1, Schedule 2, page 1 of 1, compared
13 to the COSS recommendation of a 14.53% decrease in TY 2020 and a 3.32%
14 increase in 2021.

15 **Q. Are you proposing any other lighting changes?**

16 A. Yes. Due to decreasing customer interest and the decreasing availability of higher
17 pressure sodium (“HPS”) and metal halide (“MH”) fixtures, WEPCO is proposing to
18 close the MS-3, MS-4, and GL-1 lighting schedules. In the last six months, roughly
19 2% of the roughly 1,100 light fixtures that the Company converted or installed were
20 HPS, and no MH fixtures were installed.

21 The Company is also proposing minor changes to the lighting conditions of delivery
22 as outlined in Schedule 11 of Ex.-WEPCO WG-Ferguson-1.

23 **Energy for Tomorrow**

24 **Q. Is WEPCO proposing any changes to the Energy for Tomorrow program?**

25 A. No. The Company has not made material additions to Renewable Energy Purchases
26 or Company-owned renewable energy facilities since the EFT rates were set in the
27 last rate case. Thus, the Company is not proposing any change to the EFT rates.

1 **Rules and Regulations**

2 **Q. Please describe WEPCO's proposed changes to the Minimum Payment Options**
3 **in Rule 406.2 of the Electric Rules and Regulations.**

4 A. WEPCO proposes to modify the Minimum Payment Option language to allow
5 increased flexibility in determining subsequent minimum payment amounts during the
6 collection season beyond April to September. Schedule 11 of Ex.-WEPCO WG-
7 Ferguson-1 displays WEPCO's proposed changes.

8 **Q. Are you proposing any changes to the Company's Budget Billing program?**

9 A. Yes. To simplify the Budget Billing program per preferences we have heard from our
10 customers, we are proposing changes to Electric Rules and Regulations 407.4(c),
11 which describes the periodic and continuous plans for Budget Billing.

12 **Q. What is the Company's current Budget Billing structure for under-billed and**
13 **over-billed amounts?**

14 A. The Company currently offers Periodic and Continuous Budget Billing plans. Under
15 the Periodic plan, in month 12 the customer is billed the difference between their
16 actual costs during the budget billing service year and their budget billing
17 installments. Under the Continuous plan, in month 12 this difference is rolled into and
18 made part of the next year's monthly installment amount.

19 **Q. What changes is the Company proposing and why?**

20 A. Our experience shows that our current method of handling settlement balances in
21 month 12 causes customer confusion. To reduce this confusion, we propose moving
22 to a structure that incorporates elements from both plans. Customers have expressed
23 that if they end up paying too much over a twelve-month period, they would like their
24 balance credited to them as soon as possible. However, if they did not pay enough,
25 they would prefer that debit balance to be spread over their payments for the
26 following Budget Billing year.

27

1 Accordingly, we propose to modify our Budget Billing structure so that an under-billed
2 (debit) balance is rolled into the next Budget Billing year's monthly installment
3 amount, whereas an over-billed (credit) balance will be applied against the
4 customer's account. Customers will remain able to contact us and opt to pay a debit
5 balance in full, and to receive a credit balance as a refund or roll it into the next
6 Budget Billing year's monthly installment amount if preferred.

7 **Q. How will the Company communicate this change to its customers?**

8 A. The annual service guide will explain the changes, and the Company's web page for
9 Budget Billing will be updated to reflect the change. Additionally, as current Budget
10 Billing customers reach the settlement month, a special message will be printed on
11 their bill explaining the new options.

12 **Q. When would the budget billing change take effect?**

13 A. We propose making the changes effective on a rolling basis as Budget Billing
14 customers settle their accounts after we implement our new billing system. Over the
15 course of the year following implementation, all Budget Billing customers will reach
16 month 12 and have their account settled per the new methodology.

17 **Q. Is the Company proposing changes to its Energy Information Option?**

18 A. Yes, we are proposing to close this offering to new accounts and new installations.
19 Additionally, we are requesting to terminate this offering at a future date, without
20 further Commission approval, when the Company is no longer able to deliver the
21 option as offered due to hardware and/or software incompatibilities and limitations.

22 **Q. Please describe the hardware and software issues you referenced.**

23 A. In 2016, meter manufacturers stopped producing the communication technology
24 utilized with this offering. Our existing meter supply is depleted to the point where the
25 Company can only support and maintain existing customer installations. As to
26 software, Meterlink software provides customers with dial-in access to their available
27 15-minute interval data from the billing meters. This software has limited remaining

1 vendor support due to compatibility issues with Oracle and Microsoft. When
2 Meterlink is no longer functional, participating customers will not have dial-in access
3 to their interval data. At this time, the end date for the Meterlink software is unknown.
4 Additionally, the Company's customer presentment platform, known as Energy
5 Analysis, is near its end of life. Altogether, these developments mean WEPCO will
6 soon be unable to support the Energy Information Option.

7 **Miscellaneous Electric Rate Design Changes**

8 **Q. Is WEPCO proposing to cancel any tariffs?**

9 A. Yes. WEPCO is proposing to cancel CGS-7. As approved in Docket 05-UR-107, all
10 customers were transferred from this rate schedule to CGS-NM in January of 2016.

11 **Q. Are you proposing any other changes to the rules, regulations, and rate
12 sheets?**

13 A. Yes. We are proposing numerous minor changes as reflected in Schedule 11 of Ex.-
14 WEPCO WG-Ferguson-1.

15 **Steam Utility**

16 **Description of Schedules**

17 **Q. Please describe the contents of Schedule 12 of Ex.-WEPCO WG-Ferguson-1.**

18 A. Schedule 12 shows a summary of current and proposed revenue for Wisconsin
19 Electric's steam utility by rate schedule, including the proposed dollar and percent
20 change for 2020.

21 **Q. Please describe the contents of Schedule 13 of Ex.-WEPCO WG-Ferguson-1.**

22 A. Schedule 13 shows the steam utility's test year billing data by rate schedule, current
23 and proposed revenue, and dollar and percentage rate changes for 2020. The
24 percentage rate change for each rate schedule is the percentage change for that
25 billing unit. The proposed rates in this schedule reflect a fair and equitable distribution
26 of WEPCO's jurisdictional revenue requirement, accounting for all pertinent factors.

27

1 **Q. Please describe Schedule 14 of Ex.-WEPCO WG-Ferguson-1.**

2 A. Schedule 14 shows the percentage increases applicable to the steam customers by
3 frequency with the proposed rate increases.

4 **Steam Rate Schedules**

5 **Q. Please describe the steam rate schedules.**

6 A. We offer four rate schedules for our steam customers:

7 Ag1: Downtown Milwaukee Steam Firm Service. The majority of steam customers
8 take service under this rate schedule. The rate structure includes a facilities
9 charge, customer demand charge and energy charge.

10 Ag2: Downtown Milwaukee Steam with a Condensate Return Water Credit. There
11 are currently no customers taking service under this rate schedule. The rate
12 structure includes a facilities charge, customer demand charge, energy
13 charge and a condensate water return credit.

14 Ag3: Economic Development Rate. There are currently two customers forecasted
15 to take service under this rate in 2020. The rate structure includes a facilities
16 charge, customer demand charge and energy charge. The energy charge
17 varies by the number of months the customer has taken service under this
18 tariff. Customers are subject to three timeframes: Months 1 to 60, Months 61
19 to 120, and Months 121 to 180. The energy rates increase the longer the
20 customer stays on the rate.

21 Ag4: Downtown Milwaukee Steam Non-Firm Service. There are currently four
22 customers forecasted to take service under this rate in 2020. The rate
23 structure includes a facilities charge, customer demand charge and energy
24 charge.

25

1 **Q. Please describe the overall increase and rate design for these rate schedules**
2 **and how they relate to the revenue requirement shown in Ex.-WEPCO WG-**
3 **Nelson-12.**

4 A. The 2020 revenue requirement shown in Ex.-WEPCO WG-Nelson-12 is
5 \$22,266,641. The present revenues are \$21,308,619. The 2020 revenue requirement
6 results in a 4.50% increase.

7 WEPCO is proposing an increase of 25% to all distribution charges (facilities and
8 customer demand) for all four rate schedules. The current fuel credit is shown in
9 present rates and is assumed to go to zero in the proposed rates.

10 Energy charges were decreased for each rate schedule to arrive at the \$22,266,641
11 revenue requirement. All rate schedules were held at a 4.50% increase. To achieve
12 these results, energy charges were decreased from 11% to 24% depending on the
13 rate schedule.

14 **Q. How does this proposed increase in the facilities charge and the customer**
15 **demand charge affect the split in cost recovery between the facilities charge,**
16 **customer demand charge and the energy charge?**

17 A. WEPCO intends to move towards recovering costs based on the results of the cost
18 classification analysis presented in Ex.-WEPCO WG-Nelson-12. About 72% of the
19 costs to serve the steam utility are fixed and 28% are variable according to the
20 analysis. Under the current rate design, about 86% of the costs are recovered with
21 the variable energy charge and 14% are recovered with the facilities and customer
22 demand charge. The proposed rate design would increase the cost recovery to about
23 17% through the facilities and customer demand charge.

24 **Q. If the revenue requirement changes significantly due to the Staff audit, would**
25 **your proposed revenue allocation change?**

26 A. Yes. If that occurs, WEPCO will likely submit a revised rate design proposal based on
27 the Staff audit.

1 **Other Steam Rate Changes**

2 **Q. Have you calculated new values for embedded credits for expansion of the**
3 **steam distribution systems?**

4 A. Yes. The calculated values of embedded credits for expansion of the steam
5 distribution systems are presented in Ex.-WEPCO WG-Ferguson-1, Schedule 15.

6 **Q. How were the embedded credits calculated?**

7 A. The embedded credits for the steam distribution system were derived in a manner
8 similar to that prescribed for electric embedded credits in PSC 113.1006. The
9 Commission's rules for steam in PSC 140 do not address embedded credits. The
10 depreciated costs of the steam distribution systems are divided by the total steam
11 sales using the distribution system.

12 **Q. Is WEPCO proposing any other modifications related to its steam rates?**

13 A. Yes. WEPCO is proposing to modify "Section 200 Extension of Steam Service" of its
14 Rules and Regulations. These proposed revisions are included in redline formats at
15 Schedule 11 of Ex.-WEPCO WG-Ferguson-1.

16 **Q. Why is WEPCO proposing these modifications?**

17 A. These modifications clarify that any steam distribution infrastructure installed to a
18 serve a new development and reasonably expected to serve additional future
19 customers would be subject to the Company's steam extension rules.

20 **Q. Does this conclude your pre-filed direct testimony?**

21 A. Yes, it does, but I may submit supplemental direct testimony addressing the standby
22 rate and other, minor rate modifications that are still under development as of this
23 filing, including modifications to non-firm rate schedules.