

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of)
UPPER PENINSULA POWER COMPANY)
for authority to increase retail electric rates.)
_____)

Case No. U-16417

DIRECT TESTIMONY AND EXHIBITS OF
JAMES M. BEYER
FOR
UPPER PENINSULA POWER COMPANY

June 30, 2011

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of)
UPPER PENINSULA POWER COMPANY)
for authority to increase retail electric rates.)
_____)

Case No. U-16417

**QUALIFICATIONS
OF
JAMES M. BEYER
PART I**

1 **Q. Please state your name, business address and position.**

2 A. My name is James M. Beyer. My business address is Integrys Business Support,
3 LLC ("IBS"), 700 North Adams Street, P.O. Box 19001, Green Bay, WI 54307-9001.
4 I am a Senior Rate Planner in the Regulatory Affairs Department of Integrys Energy
5 Group, Inc ("Integrys"). Both IBS and Upper Peninsula Power Company ("UPPCO")
6 are wholly-owned subsidiaries of Integrys.

7

8 **Q. For whom are you providing testimony?**

9 A. I am providing testimony on behalf of UPPCO.

10

11 **Q. Please describe briefly your educational, professional, and utility background.**

12 A. I graduated from Northern Michigan University, Marquette, Michigan with a Bachelor
13 of Science Degree in Accounting and from Lakeland College, Sheboygan, Wisconsin
14 with a Master of Business Administration ("MBA") degree. In 2004, I was employed
15 by Wisconsin Public Service Corporation ("WPS Corp") in the Regulatory Affairs
16 Department. I am involved in financial analyses and rate related studies, as well as
17 tariff development and administration.

18

1 **Q. Have you previously testified before any regulatory agency?**

2 A. Yes, I have. I have testified before the Public Service Commission of Wisconsin
3 (“PSCW”) in various rate case proceedings. I have also previously presented
4 testimony before the Michigan Public Service Commission (“MPSC”) on behalf of
5 UPPCO in Case No’s. U-15988 and U-16166, and on behalf of WPS Corp in Case
6 No. U-15352.

**JAMES M. BEYER
DIRECT TESTIMONY
PART II**

1 **Q. What is the purpose of your pre-filed direct testimony?**

2 A. My pre-filed direct testimony in this case addresses the following issues:

- 3 1. The development and presentation of UPPCO's proposed electric rate
4 design for 2012, including a proposal to consolidate the rates of the
5 Integrated and Iron River systems, as required by Order Point "N" of the
6 Commission's December 21, 2010 Order Approving Settlement
7 Agreement in Case No. U-16166.
8
9 2. UPPCO's proposal for rate realignment.
10
11 3. UPPCO's proposed electric tariff changes and/or additions regarding:
12
13 a. Additions to the lighting rules.
14
15 b. Updating the premium associated with UPPCO's NatureWise
16 tariff.
17
18 c. Revising UPPCO's Extension Allowances.
19
20 d. Miscellaneous changes to tariff language.
21
22 e. Additions and modifications to the RTMP and RTMP-D Tariff
23

24 **Q. Before describing your exhibits, please give an overview of the rate design**
25 **philosophy you followed when developing the proposed rates.**

26 A. The basic rate design philosophy is to recognize Bonbright's eight criteria of a
27 desirable rate structure. Mr. Bonbright is the author of the often-cited original edition
28 of "Principles of Public Utility Rates". These criteria are:

- 29 1. Simplicity, understandability, public acceptability, and feasibility of
30 application.
31
32 2. Freedom from controversies as to proper interpretation.
33
34 3. Effectiveness in yielding total revenue requirements.
35
36 4. Revenue stability from year to year.
37
38 5. Stability of the rates with a minimum of unexpected changes adverse to
39 existing customers.
40
41 6. Fairness of the specific rates in the apportionment of total costs of service

1
2
3
4
5
6
7
8

9

10

11
12
13
14
15
16
17
18
19
20
21
22
23
24
25

26

27

28
29
30
31
32
33
34
35
36
37
38
39
40
41
42
43
44
45

among the different consumers.

- 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).

The following are four general principles used by UPPCO when rates are developed that recognize the above criteria:

- 1. A fully-allocated, embedded Cost of Service Study ("COSS") should be used as the guiding principle for determination of revenue requirements from the individual rate schedules.
- 2. Both embedded and marginal costs should be used as guidance 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. UPPCO recognizes that should the electric rate revenue requirement change significantly, these limits and the overall rate proposals may need to be revised.
- 4. Rate design should reflect cost of service to the extent practical.

LISTING OF ITEMS ADDRESSED IN TESTIMONY

Q. What will you be addressing in connection with UPPCO's proposed rate design?

A. I will address the following items:

- 1. The General Allocation of Rate Increases;
- 2. Rate Realignment;
- 3. The Rate Design for the A-1 Residential rate schedule;
- 4. The Rate Design for the A-2 Residential rate schedule;
- 5. The Rate Design for the AH-1 Residential Heating rate schedule;
- 6. The Rate Design for the AH-2 Residential Heating rate schedule;
- 7. The Rate Design for C-1 General Service rate schedule;
- 8. The Rate Design for C-2 General Service rate schedule;

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28
29
30
31
32
33

- 9. The Rate Design for the H-1 Commercial Heating rate schedule;
- 10. The Rate Design for the H-2 Commercial Heating rate schedule;
- 11. The Rate Design for P-1 Light and Power rate schedule;
- 12. The Rate Design for P-2 Light and Power rate schedule;
- 13. The Rate Design for the Schedule A interruptible tariff;
- 14. The Rate Design for the WP-3 interruptible tariff;
- 15. The Rate Design for the Cp-U rate schedule;
- 16. Integrated and Iron River combined rate design;
- 17. The Response Rewards Program;
- 18. RTMP and RTMP-D;
- 19. Street lighting rules;
- 20. Outdoor Security Lighting rules;
- 21. Various changes to the Service Rules;
- 22. The NatureWise Program;
- 23. Various changes to the Extension rules and allowances;
- 24. The Rate Design for Self-Implemented rates.

34 **Q. Are you sponsoring any schedules?**

35 A. Yes, I am. I am sponsoring Schedules F2 – F13 of Exhibit A-6 (JMB-1).

36

37 **Q. Were these schedules prepared by you or under your direction and**
38 **supervision?**

39 A. Yes, they were.

40

41 **Q. Please describe Schedule F2 of Exhibit A-6 (JMB-1).**

42 A. Schedule F2 of Exhibit A-6 (JMB-1) displays Present and Proposed Revenues by
43 Rate Schedule. The top section of the page displays the Integrated Retail System by

1 rate schedule, while the bottom section of the page displays the Iron River System
2 by rate schedule.

3

4 UPPCO has considered the Integrated System and the Iron River System as being
5 distinct rate zones for purposes of applying the 2.50 percentage point rate
6 realignment cap of MCL 460.11(6). Therefore, the rate increase cap for any rate
7 schedule in the Integrated System is 9.47% (6.97% + 2.50%); and the rate increase
8 cap for any rate schedule in the Iron River System is 17.58% (15.08% + 2.50%).

9

10 **Q. Please describe Schedule F3 of Exhibit A-6 (JMB-1).**

11 A. Schedule F3 of Exhibit A-6 (JMB-1) contains UPPCO's proposed rate design with
12 revenue calculations by rate schedule and billing determinants for both the
13 Integrated and Iron River Systems. The proposed rates on Schedule F3 are
14 designed to recover the UPPCO revenue deficiency, and reflect the unification of the
15 P-1 and P-2 rate schedules, as well as the street lighting rate schedules, across the
16 Integrated and Iron River Systems.

17

18 **Q. What Power Supply Cost Recovery ("PSCR") factor was used to produce these
19 revenues?**

20 A. For both the Integrated Retail and Iron River Systems, a PSCR factor of -2.76 mills
21 per kWh was used to calculate revenues on both present and proposed rates.

22

23 The use of a PSCR factor of -2.76 mills per kWh is described in the pre-filed direct
24 testimony of Mr. John G. Guntlisbergen.

25

26 **Q. What factors were considered when filing this rate design?**

27 A. As part of the basic principles of rate design discussed above, UPPCO is moving the

1 rates of each rate schedule toward the cost of providing service to customers in each
2 rate schedule, as determined by UPPCO's Cost of Service Study sponsored by Ms.
3 Joylyn Hoffman Malueg.

4

5 **Q. Please describe Schedule F4 of Exhibit A-6 (JMB-1).**

6 A. Schedule F4 of Exhibit A-6 (JMB-1) calculates typical monthly bills for customers
7 served at various monthly energy and/or demand levels. Each line shows a typical
8 monthly bill under proposed rates, a typical bill under present rates, the amount of
9 the proposed rate increase, and the percent increase.

10

11 **Q. Please describe Schedule F5 of Exhibit A-6 (JMB-1).**

12 A. Schedule F5 of Exhibit A-6 (JMB-1) contains red-lined copies of the revised tariff
13 sheets UPPCO proposes to include in its filing.

14

15 **Q. Please describe Schedule F6 of Exhibit A-6 (JMB-1).**

16 A. Schedule F6 of Exhibit A-6 (JMB-1) calculates the proposed self-implemented
17 surcharge levels for each rate schedule. This exhibit was prepared in accordance
18 with MCL 460.6a(1). Listed below is a description of the contents of each column:

19

1. Rate schedule name.

20

2. Current revenues.

21

22

3. Forecasted 2012 sales in kWh.

23

24

4. Proposed revenues based on the proposed self-implemented rate
increase.

25

26

27

5. Proposed self-implemented rate increase.

28

29

6. Proposed surcharge for each rate schedule.

30

31

32 As authorized by MCL 460.6a(1), UPPCO intends to self-implemented rates for
33 service rendered on and after January 1, 2012. A proposed tariff sheet can be found

1 in Schedule F5 of Exhibit A-6 (JMB-1), page 42.

2
3 **ALLOCATION OF RATE INCREASES**

4 **Q. Could you provide a general overview of the intent of UPPCO's proposed**
5 **revenue allocation?**

6 A. UPPCO's proposed revenue allocation provides higher rate increases for particular
7 rate schedules in which the existing rate levels do not sufficiently recover the costs to
8 provide service to these rate schedules. Rate schedules for which the current rate
9 levels exceed the costs to provide service to these rate schedules were provided
10 lower rate increases. This was done in an effort to continue to realign the rates and
11 move the rate levels of each of the rate schedules toward levels that better reflect the
12 cost of providing service to each rate schedule, as required by MCL 460.11(6).

13
14 **Q. Do UPPCO's proposed rates eliminate subsidizations?**

15 A. No, they do not. The realignment of rates generally takes several general rate cases
16 to implement. Further, MCL 460.11(6) prohibits UPPCO from increasing rates to any
17 one rate schedule by more than 2.5 percentage points above the overall increase.
18 Therefore, the rate increase cap for any rate schedule in the Integrated System is
19 9.47% (6.97% + 2.50%); and the rate increase cap for any rate schedule in the Iron
20 River System is 17.58% (15.08% + 2.50%).

21
22 Complete elimination of the rate schedule cross-subsidies would require very large
23 rate increases to some rate schedules, which would exceed the 2.5 percentage point
24 cap of MCL 460.11(6). For example, the A-1 residential rate schedule would be
25 required to receive a 16.99% base rate increase to eliminate the cross-subsidies by
26 the other rate schedules. As discussed previously, having rate levels reflect cost of
27 service is only one of several principles UPPCO used in developing the proposed

1 rate design. Managing rate impacts and other prudent rate design principles
2 discussed previously were also utilized.

3

4 **Q. Is there also a need to realign rates within a rate schedule?**

5 A. Yes, there is. Customer service requirements and characteristics vary within rate
6 schedules. Some of these items impact the costs to provide service, while others
7 may not. The goal of rate design is to have rates reflect cost causation to the extent
8 practical. Electric utilities generally have a high fixed cost profile to provide basic
9 service to customers, regardless of the amount of consumption a customer may
10 have. These fixed costs do not vary with the amount of electricity a customer uses
11 and includes, but is not limited to, the cost of owning and maintaining electric meters,
12 services to the house, line transformers, and the necessary distribution system to
13 provide service, as well as meter reading and billing. To the degree these costs are
14 not recovered in a fixed monthly charge, but instead in a charge based on
15 consumption, customers with higher consumption levels will subsidize the customers
16 with lower consumption levels. Increasing the monthly service charges more than
17 the energy charges is one method to realign within a rate schedule.

18

19 **Q. Please explain UPPCO's proposed rate realignment plan required by MCL
20 460.11(6).**

21 A. UPPCO is proposing a rate realignment plan as shown on Schedule F12 of Exhibit
22 A-6 (JMB-1). The overall revenue requirement remains constant by increasing the
23 revenue collected from rate schedules with revenue deficiencies as shown in the
24 UPPCO COSS, and decreasing the revenue collected from rate schedules with
25 revenue excesses as shown in the UPPCO COSS.

26

27 Due to the 2.5 percentage point cap of MCL 460.11(6) and the approximately 42%

1 revenue deficiency for the Z-3 rate schedule, customer rates are not completely
2 realigned in this plan until 2023.

3

4 **Q. Please explain how UPPCO is proposing to realign customer rates.**

5 A. UPPCO is proposing an annual \$/kWh adjustment to the affected rate schedules.
6 The annual adjustment was calculated by dividing the proposed revenue increase or
7 decrease by the forecasted kWh sales for each rate schedule.

8

9 **Q. Please explain when these charges would go into effect.**

10 A. These annual \$/kWh adjustments would be modified annually, on a service rendered
11 basis, on the anniversary of the effective date of the Commission's order in the
12 instant general rate case proceeding.

13

14 **Q. Are the rate increases proposed by UPPCO for the Iron River System
15 supported by UPPCO's COSS?**

16 A. Yes, they are. The UPPCO COSS allocates approximately \$9.6 million of costs to
17 the Iron River System. To match the UPPCO COSS, an approximate \$1.3 million, or
18 15%, rate increase would be required for the Iron River System. Even with the
19 proposed 10.20% increase for the Iron River system, the proposed revenue from the
20 Iron River System will only be approximately \$9.2 million, which is approximately
21 \$0.4 million less than what the UPPCO COSS indicates.

22

23 **Q. Please describe UPPCO's proposed revenue allocation for the Iron River
24 System.**

25 A. In an effort to move the rates of Iron River System customers toward the rates of
26 Integrated Retail System customers, rate schedules A-2, AH-2, and Z-4 were given a
27 13.50% increase. Rate schedule C-2 and H-2 were given a 10.00% and 4.49%

1 increase respectively. Cp-U was given a 5.41% increase. UPPCO is also proposing
2 to combine the P-2 rate with the P-1 rate in the Integrated System which would result
3 in a 10.06% increase to the P-2 rate schedule. Iron River street lighting (SL-10) is
4 proposed to be combined with the Integrated System's SL-6 rate schedule. This
5 results in a 9.69% increase to the Iron River street lighting rate schedule. Even with
6 these proposed increases, the Iron River System rates are below their equivalent
7 Integrated Retail System rates, and below their cost of service.

8

9 **Q. Please describe how UPPCO allocated the revenues for the Integrated Retail**
10 **System.**

11 A. Rate schedules with under-recoveries in the COSS in excess of 8% were capped at
12 a rate increase of 9.47%. Due to the fact that MCL 460.11(6) prohibits UPPCO from
13 increasing rates to any one rate schedule by more than 2.5 percentage points above
14 the overall increase, the remaining rate schedules are proposed to have increases in
15 the range of 2.00% - 5.50%.

16

17 **Q. Is UPPCO proposing new rates or tariffs specifically for low-income and senior**
18 **citizen customers as discussed in MCL 460.11(3)?**

19 A. No, it is not, as MCL 460.11(5) exempts UPPCO from this requirement because
20 UPPCO serves less than 1,000,000 customers.

21

22 **Q. Is UPPCO proposing new rates or tariffs specifically for public and private**
23 **schools, universities, and community colleges as discussed in MCL 460.11(4)?**

24 A. No, it is not, as MCL 460.11(5) exempts UPPCO from this requirement because
25 UPPCO serves less than 1,000,000 customers.

26

27

1 **RESIDENTIAL RATE DESIGN – A-1**

2 **Q. Please describe UPPCO’s proposed rate design for the A-1 rate schedule in the**
3 **Integrated Retail System.**

4 A. The A-1 rate schedule has historically been subsidized by other rate schedules. The
5 existing rate levels are forecasted to under-recover the revenue requirement for this
6 rate schedule by approximately 16.99%. UPPCO’s proposed rate design reflects
7 UPPCO’s desire to eventually eliminate these historical subsidies, and better align
8 rates with cost causation. The monthly service charge for the A-1 rate schedule was
9 increased by \$1.00/month for year-round customers to \$11.00 per month. The
10 energy charge was increased from \$0.17135/kWh (including the base rate of
11 \$0.17411/kWh plus the PSCR factor of -0.00276/kWh) to \$0.18746/kWh. These
12 proposed rate changes reflect a 9.47% overall rate increase.

13
14 It should be noted that even with the proposed rate increases, the A-1 rate schedule
15 would still be paying less than the cost to provide electric service to that rate
16 schedule based on UPPCO’s COSS. Thus, further rate realignment will be required
17 as shown on Schedule F12 of Exhibit A-6 (JMB-1).

18
19 **RESIDENTIAL RATE DESIGN – A-2**

20 **Q. Please describe UPPCO’s proposed rate design for the A-2 residential rate**
21 **schedule in the Iron River System.**

22 A. The monthly service charge for the A-2 rate schedule was increased \$1.00/month to
23 \$11.00 per month. The customer charge was increased to match the customer
24 charge of the equivalent rate (A-1) in the Integrated Retail System. The energy
25 charge was increased from \$0.15589/kWh (\$0.15865/kWh base plus -
26 \$0.00276/kWh) to \$0.17769/kWh. These proposed rate changes reflect a 13.50%
27 overall rate increase.

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27

COMBINED RESIDENTIAL RATE DESIGN – A-3

Q. Please describe UPPCO’s proposed rate design for the A-3 residential rate schedule in the combined UPPCO system.

A. Order Point “N” of the Commission’s December 21, 2010 Order Approving Settlement Agreement in Case No. U-16166 requires UPPCO to include in the instant general rate case filing a proposal for rate consolidation of the Integrated and Iron River systems. The existing rate levels are forecasted to under-recover the revenue requirement for this rate schedule by approximately 17.41% in the Combined Retail COSS. Under the combined rate schedule, the average A-1 customer would see a 9.47% increase and the average A-2 customer would see a 19.02% increase.

RESIDENTIAL ELECTRIC HEATING RATE DESIGN – AH-1

Q. Please describe UPPCO’s proposed rate design for the AH-1 rate schedule in the Integrated Retail System.

A. The monthly service charge for the AH-1 rate schedule was increased by \$1.00/month for year round customers to \$11.00 per month. The energy charge for the summer months is proposed to increase from \$0.17327/kWh (including the base rate of \$0.17603/kWh plus the PSCR factor of -\$0.00276/kWh) to \$0.18955/kWh, and the first 500 kWh for winter is proposed to increase from \$0.17135/kWh (including the base rate of \$0.17411/kWh plus the PSCR factor of -\$0.00276/kWh) to \$0.18746/kWh. The energy charge for the winter months in excess of 500 kWh is proposed to increase from \$0.14117/kWh (including the base rate of \$0.14393/kWh plus the PSCR factor of -\$0.00276/kWh) to \$0.15452/kWh. These proposed rate changes reflect a 9.47% overall rate increase.

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27

RESIDENTIAL ELECTRIC HEATING RATE DESIGN – AH-2

Q. Please describe UPPCO’s proposed rate design for the AH-2 rate schedule in the Iron River System.

A. The monthly service charge for the AH-2 rate schedule was increased by \$1.00/month for year round customers to \$11.00 per month. The energy charge for the summer months is proposed to increase from \$0.19238/kWh (including the base rate of \$0.19514/kWh plus the PSCR factor of -\$0.00276/kWh) to \$0.21919/kWh, and the first 500 kWh for winter is proposed to increase from \$0.15589/kWh (including the base rate of \$0.15865/kWh plus the PSCR factor of -\$0.00276/kWh) to \$0.17769/kWh. The energy charge for the winter months in excess of 500 kWh was increased from \$0.13263/kWh (including the base rate of \$0.13539/kWh plus the PSCR factor of -\$0.00276/kWh) to \$0.15051/kWh. These proposed rate changes reflect a 13.50% overall rate increase.

COMBINED RESIDENTIAL ELECTRIC HEATING RATE DESIGN – AH-3

Q. Please describe UPPCO’s proposed rate design for the AH-3 residential heating rate schedule in the combined UPPCO system.

A. Order Point “N” of the Commission’s December 21, 2010 Order Approving Settlement Agreement in Case No. U-16166 requires UPPCO to include in the instant general rate case filing a proposal for rate consolidation of the Integrated and Iron River systems. The existing rate levels are forecasted to under-recover the revenue requirement for this rate schedule by approximately 8.31% in the Combined Retail COSS. Under the combined rate schedule, the average AH-1 customer would see a 9.97% increase and the average AH-2 customer would see a 13.26% increase.

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27

GENERAL SERVICE RATE DESIGN – C-1

Q. Please describe UPPCO’s proposed rate design for the C-1 General Service rate schedule in the Integrated Retail System.

A. The monthly service charge for the rate schedule was increased \$1.00/month to \$15.00 per month, and the energy charge was increased from \$0.17797/kWh (\$0.18073/kWh base plus the PSCR factor of -\$0.00276/kWh) to \$0.18754/kWh. These proposed rate changes reflect a 5.50% overall rate increase.

GENERAL SERVICE RATE DESIGN – C-2

Q. Please describe UPPCO’s proposed rate design for the C-2 General Service rate schedule in the Iron River System.

A. The monthly service charge for the C-2 rate schedule was increased \$1.00/month to \$15.00/month to match the customer charge of the equivalent C-1 rate in the Integrated Retail System. The energy charge was increased from \$0.15566/kWh (\$0.15842 base rates plus the PSCR factor -\$0.00276/kWh) to \$0.17153/kWh. These proposed rate changes reflect a 10.00% overall rate increase.

COMBINED GENERAL SERVICE RATE DESIGN – C-3

Q. Please describe UPPCO’s proposed rate design for the C-3 commercial rate schedule in the combined UPPCO system.

A. Order Point “N” of the Commission’s December 21, 2010 Order Approving Settlement Agreement in Case No. U-16166 requires UPPCO to include in the instant general rate case filing a proposal for rate consolidation of the Integrated and Iron River systems. The existing rate levels are forecasted to over-recover the revenue requirement for this rate schedule by approximately 2.08% in the Combined Retail COSS. Under the combined rate schedule, the average C-1 customer would see a 3.87% increase and the average C-2 customer would see a 17.75% increase.

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27

COMMERCIAL ELECTRIC HEATING RATE DESIGN – H-1

Q. Please describe UPPCO’s proposed rate design for the H-1 rate schedule in the Integrated Retail System.

A. The monthly service charge for the H-1 rate schedule was increased by \$1.00/month for year round customers to \$15.00 per month. The energy charge for the summer months is proposed to increase from \$0.18032/kWh (including the base rate of \$0.18308/kWh plus the PSCR factor of -\$0.00276/kWh) to \$0.18126/kWh, and the first 1,000 kWh for winter is proposed to increase from \$0.17798/kWh (including the base rate of \$0.18074/kWh plus the PSCR factor of -\$0.00276/kWh) to \$0.17891/kWh. The energy charge for the winter months in excess of 1,000 kWh was increased from \$0.12897/kWh (including the base rate of \$0.13173/kWh plus the PSCR factor of -\$0.00276/kWh) to \$0.13349/kWh. These proposed rate changes reflect a 2.07% overall rate increase.

COMMERCIAL ELECTRIC HEATING RATE DESIGN – H-2

Q. Please describe UPPCO’s proposed rate design for the H-2 rate schedule in the Iron River System.

A. The monthly service charge for the H-2 rate schedule was increased by \$1.00/month for year round customers to \$15.00 per month. The energy charge for the summer months is proposed to increase from \$0.15867/kWh (including the base rate of \$0.16143/kWh plus the PSCR factor of -\$0.00276/kWh) to \$0.17484/kWh, and the first 1,000 kWh for winter is proposed to increase from \$0.15566/kWh (including the base rate of \$0.15842/kWh plus the PSCR factor of -\$0.00276/kWh) to \$0.17153/kWh. The energy charge for the winter months in excess of 1,000 kWh was increased from \$0.12880/kWh (including the base rate of \$0.13156/kWh plus the PSCR factor of -\$0.00276/kWh) to \$0.12796/kWh. These proposed rate

1 changes reflect a 4.49% overall rate increase.

2
3 **COMBINED COMMERCIAL ELECTRIC HEATING RATE DESIGN – H-3**

4 **Q. Please describe UPPCO’s proposed rate design for the H-3 commercial heating**
5 **rate schedule in the combined UPPCO system.**

6 A. Order Point “N” of the Commission’s December 21, 2010 Order Approving
7 Settlement Agreement in Case No. U-16166 requires UPPCO to include in the
8 instant general rate case filing a proposal for rate consolidation of the Integrated and
9 Iron River systems. The existing rate levels are forecasted to over-recover the
10 revenue requirement for this rate schedule by approximately 13.98% in the
11 Combined Retail COSS. Under the combined rate schedule, the average H-1
12 customer would see a 1.53% increase and the average H-2 customer would see a
13 8.07% increase.

14
15 **COMMERCIAL AND INDUSTRIAL DEMAND AND ENERGY RATE SCHEDULES**

16
17 **POWER & LIGHT SERVICE RATE DESIGN – P-1**

18 **Q. Please describe UPPCO’s proposed rate design for the P-1 Light and Power**
19 **Service rate schedule in the Integrated Retail System.**

20 A. The monthly service charge for the rate schedule was increased \$3.00/month to
21 \$28.00 per month, and the energy charge was increased from \$0.10419/kWh
22 (\$0.10695/kWh base plus the PSCR factor of -\$0.00276/kWh) to \$0.11052/kWh.
23 These proposed rate changes reflect a 5.49% overall rate increase.

24
25 **POWER & LIGHT SERVICE RATE DESIGN – P-2**

26 **Q. Please describe UPPCO’s proposed rate design for the P-2 Light and Power**
27 **Service rate schedule in the Iron River System.**

1 A. The monthly service charge for the rate schedule was increased by \$3.00/month to
2 \$28.00 per month, and the energy charge was increased from \$0.10865/kWh
3 (\$0.11141/kWh base plus the PSCR factor of -\$0.00276/kWh) to \$0.11052/kWh.
4 These proposed rate changes reflect a 10.06% overall rate increase.

5

6 **COMBINED POWER & LIGHT SERVICE RATE DESIGN – P-3**

7 **Q. Please describe UPPCO’s proposed rate design for the P-3 power and light**
8 **rate schedule in the combined UPPCO system.**

9 A. Order Point “N” of the Commission’s December 21, 2010 Order Approving
10 Settlement Agreement in Case No. U-16166 requires UPPCO to include in the
11 instant general rate case filing a proposal for rate consolidation of the Integrated and
12 Iron River systems. The existing rate levels are forecasted to over-recover the
13 revenue requirement for this rate schedule by approximately 2.01% in the Combined
14 Retail COSS. Under the combined rate schedule, the average P-1 customer would
15 see a 4.81% increase and the average P-2 customer would see a 9.37% increase.

16

17 **LARGE LIGHT AND POWER – TRANSMISSION AND DISTRIBUTION RATE DESIGN –**

18

Cp-U

19 **Q. Please describe UPPCO’s proposed rate design for the Cp-U Large Light and**
20 **Power Service rate schedule in the Integrated and Iron River Retail System.**

21 A. UPPCO’s COSS shows rate schedule Cp-U (Integrated System) recovering 2.70%
22 more revenue than the costs assigned to it. UPPCO is proposing an overall rate
23 increase of 5.36% to customers currently on the Cp-U (Integrated System) rate
24 schedule.

25

26 UPPCO’s COSS shows rate schedule Cp-U (Iron River System) recovering 21.19%
27 less revenue than the costs assigned to it. UPPCO is proposing an overall rate

1 increase of 5.41% to customers currently on the Cp-U (Iron River System) rate
2 schedule.

3

4 UPPCO is proposing to increase the demand charge levels from \$13.00/kW to
5 \$13.50/kW for secondary, \$12.65/kW to \$13.14/kW for primary, and \$12.03/kW to
6 \$12.49/kW for transmission.

7

8 UPPCO is not proposing to increase customer demand charges for secondary or
9 primary in this case.

10

11 UPPCO is proposing to increase the interruptible demand charge levels from
12 \$5.50/kW to \$6.00/kW for secondary, \$5.15/kW to \$5.84/kW for primary, and
13 \$4.53/kW to \$5.55/kW for transmission.

14

15 Customer charges are proposed to be increased by \$50/month to \$300/month for
16 secondary, \$375/month for primary and \$800/month for transmission.

17

18 The substation transformer charge is proposed to be increased by \$0.10/kVa to
19 \$0.70/kVa.

20

21 UPPCO is proposing to increase the on-peak energy charge levels from
22 \$0.09366/kWh to \$0.09863/kWh for secondary, \$0.09147/kWh to \$0.09632/kWh for
23 primary and \$0.08802/kWh to \$0.09269 for transmission. Both current and proposed
24 energy charges include a PSCR factor of -\$0.00276/kWh.

25

26 UPPCO is proposing to increase the off-peak energy charge levels from
27 \$0.05992/kWh to \$0.06314/kWh for secondary, \$0.05849/kWh to \$0.06164/kWh for

1 primary and \$0.05625/kWh to \$0.05928 for transmission. Both current and proposed
2 energy charges include a PSCR factor of -\$0.00276/kWh.

3

4 **Q. How are the Cp-U customers affected by the combined rate design?**

5 A. In the combined rate design the average Cp-U customer on the integrated system
6 will see a 5.20% increase and the average customer on Iron River system will see a
7 5.24% increase.

8

9 **Q. Please describe Schedule F7 of Exhibit A-11 (JMB-1).**

10 A. Schedule F7 shows the annual bill impacts of those customers currently taking
11 service under the Cp-U rate schedule. The first column indicates the individual
12 customer (identified by number, not name), the second column is the annual bill
13 under the current rates, the third column is the annual bill under the proposed rates,
14 and the last column displays the percentage change in the annual bill.

15

16 **Q. Please describe Schedule F8 of Exhibit A-11 (JMB-1).**

17 A. Schedule F8 shows the % increases applicable to Cp-U customers by frequency
18 under the proposed rates.

19

20 **LARGE LIGHT AND POWER — SCHEDULE A**

21 **Q. Please describe UPPCO's proposed rate design for the Schedule A Large Light
22 and Power Service rate schedule in the Integrated Retail System.**

23 A. UPPCO is proposing to increase the demand charge levels from \$12.03/kW to
24 \$12.49/kW and the interruptible demand charge levels from \$4.53/kW to \$4.99/kW.

25

26 The on-peak energy charge was changed from \$0.07718/kWh (including the base
27 rate of \$0.07994/kWh plus the PSCR factor of -\$0.00276/kWh) to \$0.07774/kWh.

1 The off-peak energy charge was increased from \$0.04742/kWh (including the base
2 rate of \$0.05018/kWh plus the PSCR factor of -\$0.00276/kWh) to \$0.04777/kWh.

3

4 The customer charge for this rate schedule is being proposed to increase by
5 \$50/month to \$800/month.

6

7 The substation transformer charge is proposed to be increased by \$0.10/kVa to
8 \$0.70/kVa.

9

10 **LARGE LIGHT AND POWER — WP-3**

11 **Q. Please describe UPPCO's proposed rate design for the WP-3 Large Light and**
12 **Power Service rate schedule in the Integrated Retail System.**

13 A. UPPCO's COSS shows rate schedule WP-3 recovering 8.34% more revenue than
14 the costs assigned to it. UPPCO is proposing an overall rate increase of 2.00% to
15 the WP-3 rate schedule.

16

17 UPPCO is proposing to increase the demand charge levels from \$12.03/kW to
18 \$12.49/kW and the interruptible demand charge levels from \$4.53/kW to \$4.99/kW

19

20 The on-peak energy charge was increased from \$0.6998/kWh (including the base
21 rate of \$0.07274/kWh plus the PSCR factor of -\$0.00276/kWh) to \$0.07002/kWh.

22 The off-peak energy charge was increased from \$0.04534/kWh (including the base
23 rate of \$0.04810/kWh plus the PSCR factor of -\$0.00276/kWh) to \$0.04537/kWh.

24

25 The customer charge for this rate schedule is being proposed to increase by
26 \$50/month to \$800/month.

27

1 The substation transformer charge is proposed to be increased by \$0.10/kVa to
2 \$0.70/kVa.

3

4 **Q. How is rate schedule WP-3 affected by the combined rate design?**

5 A. In the combined rate design the WP-3 rate schedule will see a 2.03% rate increase.

6

7

REAL TIME MARKET PRICING — RTMP

8 **Q. Is UPPCO proposing any modifications to the Real Time Market Pricing**
9 **(“RTMP”) tariff?**

10 A. UPPCO is proposing changes and additions to the RTMP tariff related to renewable
11 energy, transmission costs, non-compliance penalties, clarification on the term of the
12 contract and pricing node.

13

14 **Q. Please describe the renewable energy charge that is being proposed for the**
15 **RTMP tariff.**

16 A. UPPCO is proposing to add a renewable energy charge to the tariff to reflect costs
17 incurred for the Company to meet state or federal renewable portfolio standard(s)
18 (“RPS”). An RPS requires the Company to provide minimum amounts of renewable
19 energy as part of its supply portfolio, usually on a percentage basis. For example,
20 the current state RPS in Michigan is 10%. A 10% RPS requires UPPCO to generate
21 or purchase enough renewable generation/credits to cover 10% of the Company’s
22 kWh sales.

23

24 The customer shall choose one of the following options on an annual basis or a
25 combination of the two:

- 26 • The customer may choose to self supply the credits by providing renewable
27 energy credits to the Company for the Company to include in the renewable
28 energy tracking system to meet the RPS, or

- 1 • The customer shall pay the Company for the quantity of renewable energy
2 required to meet the RPS for the energy the customer purchased under the
3 RTMP rate schedule, priced at the applicable NatureWise rate schedule.

4

5 **Q. Please describe the changes to the transmission costs that are being**
6 **proposed for the RTMP tariff.**

7 A. UPPCO is proposing to modify the transmission language to represent all
8 transmission costs assessed by the transmission provider to UPPCO for the Real
9 Time Market Pricing customers. Currently, the transmission service tariff language
10 only assesses transmission charges based on the coincident peak demand of the
11 customer to UPPCO's coincident peak demand of the American Transmission
12 Company. These costs are based on the actual costs and loads of the RTMP
13 customer and UPPCO.

14

15 UPPCO is proposing this tariff language to provide the company with tariff language
16 to recover the actual costs from the RTMP customers and providing flexibility to
17 adapt to changing transmission pricing tariffs and practices. For example, in the
18 future, some portion of the future transmission investment in MISO will be allocated
19 to UPPCO based on \$/MWh consumption for multi-value projects ("MVP"s). MVP is
20 a new classification and cost allocation for transmission upgrades within the MISO
21 that provide footprint-side benefits. The MISO tariff for these charges was approved
22 by FERC in Docket No. ER10-1791.

23

24 UPPCO would like to modify the transmission service section of the RTMP tariff to
25 include all charges assessed by the transmission provider to UPPCO for the RTMP
26 customer.

27

1 **Q. Please describe the penalty for non-compliance that the Company is**
2 **proposing to add to the RTMP tariff.**

3 A. The RTMP rate schedule is for customers that choose to have 100% of their load as
4 interruptible. Since interruptible load is not included in the MISO Resource
5 Adequacy Requirement, UPPCO needs to ensure that this load is removed when a
6 reliability interruption occurs. To do this, UPPCO is proposing a financial penalty for
7 failure to remove non-firm load when a customer is notified of an interruption. The
8 proposed penalty will be the higher of the following:

- 9 • \$40/kW of the highest 15 minute demand of the non-firm load that was no
10 interrupted during the interruption period, or
- 11 • The incremental costs incurred by the Company as a result of the
12 customer's failure to comply with the interruption plus 10%. Incremental
13 costs include but are not limited to purchased power costs, energy
14 imbalance and other MISO fees, and fees and costs assessed by the
15 applicable regional reliability council, or other state or federal agency.

16

17 **Q. Please describe the contract language that is being proposed for the RTMP**
18 **rate schedule.**

19 A. The new contract language clarifies when a customer needs to sign up for the
20 program for service starting on January first of the following year, and when the
21 customer may return to service under this rate schedule once they have left.

22

23 **Q. Please describe the sign-up process for this rate schedule.**

24 A. Customers need to sign-up for the tariff by April 15th of the preceding year to start
25 service on January of the following year. For example, if a customer desires to take
26 service under this rate schedule starting on January 1, 2012, they must sign a
27 contract by April 15, 2011. Contracts are a minimum of one year with a 90 day

1 cancellation notice. To minimize customers switching back and forth from this rate
2 schedule to the Cp-I rate schedule, UPPCO is proposing that customers must wait a
3 minimum of one year before returning to the program once they leave the program.
4 The Company also reserves the right to deny service under this rate schedule if this
5 load has not been forecasted in a rate case proceeding and may cause harm to the
6 Company or other customers.

7

8 **Q. Please describe UPPCO's modification to the tariff regarding pricing nodes.**

9 A. Currently, the UPPC.Integrated node or its successor is listed in the tariff. UPPCO
10 would like to add language that allows the Company to utilize a different pricing
11 node, with a 90-day written notice to the customer. Utilizing a different pricing node
12 would be done if another pricing node would better reflect the costs caused by the
13 customer load and the use of that node would be a benefit to other UPPCO system
14 customers.

15

16 **REAL TIME MARKET PRICING DISTRIBUTION SERVICE — RTMP-D**

17 **Q. Is UPPCO proposing any modifications to the Real Time Market Pricing**
18 **("RTMP-D") tariff?**

19 A. UPPCO is proposing changes and additions to the RTMP tariff related to
20 transmission costs, delivery service charges and pricing nodes.

21

22 **Q. Please describe the changes to the transmission costs that are being**
23 **proposed for the RTMP-D tariff.**

24 A. UPPCO is proposing to modify the transmission language to represent all
25 transmission costs assessed by the transmission provider to UPPCO for the Real
26 Time Market Pricing (Distribution) customers. Currently, the transmission service
27 tariff language only assesses transmission charges based on the coincident peak

1 demand of the customer to UPPCO's coincident peak demand of the American
2 Transmission Company. These costs are based on the actual costs and loads of the
3 RTMP-D customers and UPPCO.

4
5 In the future, some portion of the future transmission investment in MISO will be
6 allocated to UPPCO based on \$/MWh consumption for multi-value projects ("MVP"s).
7 MVP is a new classification and cost allocation for transmission upgrades within the
8 MISO that provide footprint-side benefits. The MISO tariff for these charges was
9 approved by FERC in Docket No. ER10-1791.

10
11 UPPCO would like to modify the transmission service section of the RTMP-D tariff to
12 include all charges assessed by the transmission provider to UPPCO for the RTMP-
13 D customers.

14

15 **Q. Please describe the changes to the language of the delivery charges that are**
16 **being proposed for the RTMP-D tariff.**

17 A. The current tariff lists the substation transformer capacity charge. The customer is
18 only charged this rate on their original tariff. For clarification purposes UPPCO is
19 proposing to remove the substation charge and replace it with a line explaining that
20 the customer's distribution charges can be found on their applicable tariff.

21

22 **Q. Please describe UPPCO's modification to the tariff regarding pricing nodes.**

23 A. UPPCO would like to add language that allows the Company to utilize a different
24 pricing node, with a 90-day written notice to the customer. Utilizing a different pricing
25 node would be done if another pricing node would better reflect the costs caused by
26 the customer load and the use of that node would be a benefit to other UPPCO
27 system customers.

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27

RESPONSE REWARDS (CP-RR)

Q. Please describe Schedule F9 of Exhibit A-6 (JMB-1).

A. Schedule F9 of Exhibit A-6 (JMB-1) displays the proposed rate design of the Response Rewards program for secondary, primary, and transmission customers. The rate was designed to be breakeven for an average Cp-U secondary customer. The Response Rewards demand and energy pricing for primary and transmission customers vary by the same loss factors used in the standard Cp-U rate design.

Q. Please define the Response Rewards rate.

A. The rate is an optional commercial/industrial rate designed to offer customers the opportunity to save money by reducing load during UPPCO's high-priced generation/purchased power times. The program provides the commercial/industrial customers more rate options, sends better price signals, and should result in peak-load shifting which reduces costs for all customers.

Q. What customers are eligible for the Response Rewards program?

A. Commercial/industrial customers that currently qualify for the Cp-U rate are eligible for the CP Response Rewards program ("CP-RR"). The CP-RR rate has been in place since 2007 and currently has no participants.

Q. Please describe the Response Rewards concept.

A. The CP-RR rate is similar to the Cp-U rate. Both rates have a customer charge, a customer demand charge, a system demand charge and on/off-peak energy rates. The corresponding rates differ only in their energy and system demand rates. The Response Rewards program offers lower system demand rates and lower on-peak and off-peak energy rates during 8,460 hours of the year, in exchange for 300 hours

1 of higher priced energy.

2

3 **Q. When will the customers be paying higher priced energy costs?**

4 A. The customer is subject to the 300 hours of the higher priced energy at anytime of
5 the day, and on any day of the week. UPPCO will communicate to the customer at
6 least one hour prior to starting an event that the price will be going up to the critical
7 peak price.

8

9 **Q. What pricing levels is UPPCO proposing for the Response Rewards system
10 demand charge, on-peak and off-peak energy rates, and how do these levels
11 compare to the standard rates?**

12 A. UPPCO is proposing the following energy prices for the CP-RR tariff.

13

CP Response Rewards		
Billing Parameter	Response Rewards (Secondary*)	Cp (Secondary*)
System Demand	\$10.13	\$13.50
On-Peak	\$0.09795	\$0.10139
Off Peak	\$0.05931	\$0.06600
Critical Peak	\$0.50000	NA

14

15

16

*The CP-RR energy pricing for primary and transmission customers vary by the same loss factors used in the standard Cp-U rate design.

17 **Q. How much load will the customer need to reduce to save money on this rate?**

18 A. The CP-RR rate factors were designed to be revenue neutral for the rate schedule
19 as a whole. If the average customer takes no action during the higher priced energy
20 times, the average customer will break even on an annual basis. If the average
21 customer reduces load during the critical peak hours, the customer has the

1 opportunity to save money.

2

3 **Q. Will all customers break-even on the Response Rewards rate?**

4 A. Since the billing units are based on an average customer, the results will vary for
5 each customer if they take no action.

6

7 **DUSK TO DAWN LIGHTING – Z-3, Z-4**

8 **Q. Please describe UPPCO’s proposed rate design for the Z-3 and Z-4 rate
9 schedules.**

10 A. UPPCO is proposing an overall rate increase of 9.47% for the above listed dusk to
11 dawn outdoor security lighting rate schedules in the Integrated Retail System, and a
12 13.50% increase to the Iron River System. UPPCO’s COSS indicates an under-
13 recovery of 42.28% for the Integrated Retail System (Z-3), and an under-recovery of
14 33.35% in the Iron River System (Z-4).

15

16 **COMBINED DUSK TO DAWN LIGHTING – Z-5**

17 **Q. Please describe UPPCO’s proposed rate design for the Z-5 dusk to dawn
18 lighting rate schedule in the combined UPPCO System.**

19 A. Order Point “N” of the Commission’s December 21, 2010 Order Approving
20 Settlement Agreement in Case No. U-16166 requires UPPCO to include in the
21 instant general rate case filing a proposal for rate consolidation of the Integrated and
22 Iron River systems. The existing rate levels are forecasted to under-recover the
23 revenue requirement for this rate schedule by approximately 41.05% in the
24 Combined Retail COSS. Under the combined rate schedule, the average Z-3
25 customer would see a 7.12% increase and the average Z-4 customer would see a
26 36.74% increase.

27

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27

STREET LIGHTING –SL-3, SL-5, SL-6, SL-10

Q. Please describe UPPCO’s proposed rate design for the street lighting rate schedules.

A. UPPCO is proposing to combine the Iron River and Integrated street lighting tariffs with this rate case. Rate schedules SL-3, SL-5 and SL-6 would be opened up to the Iron River district and rate schedule SL-10 will be eliminated. Iron River customers currently on the SL-10 rate schedule would be moved to SL-6.

UPPCO is proposing an overall rate increase of 9.47% for the SL rate schedules in the Integrated Retail System, and 9.69% in the Iron River System. UPPCO’s COSS indicates an under-recovery of 13.35% for the Integrated Retail System (SL-3, 5, 6), and an under-recovery of 15.19% in the Iron River System (SL-10).

Q. Is UPPCO proposing any other changes to the street lighting tariffs?

A. Yes it is. UPPCO is proposing to modify the current rate design of the SL-3 tariff. Under the current tariff, the customer is charged only on energy usage. UPPCO is proposing to add a customer charge and reduce the energy charge. The customer charge was set at the same rate as the C-1 rate schedule, which is \$15.00.

Q. Is UPPCO proposing any changes to the street lighting rules?

A. Yes it is. UPPCO is proposing to add and expand on some of the rules in the current tariff. These rules are being proposed to be more consistent with WPS Corp. Both rules are associated with SL-5 (customer-owned street lighting). The first rule asks the customer to make the company aware of any changes to poles and fixtures after initial installation. The second is in regards to the maintenance of customer-owned ornamental street lighting and the company’s responsibility associated with the maintenance. The language describes normal maintenance within the term of the

1 customer's contract.

2

3

COMBINED STREET LIGHTING –SL

4 **Q. Please describe UPPCO's proposed rate design for the Street Lighting rate**
5 **schedule in the combined UPPCO System.**

6 A. Order Point "N" of the Commission's December 21, 2010 Order Approving
7 Settlement Agreement in Case No. U-16166 requires UPPCO to include in the
8 instant general rate case filing a proposal for rate consolidation of the Integrated and
9 Iron River systems. The existing rate levels are forecasted to under-recover the
10 revenue requirement for this rate schedule by approximately 13.36% in the
11 Combined Retail COSS. Under the combined rate schedule, the average Integrated
12 street lighting customer would see a 10.11% increase and the average Iron River
13 street lighting customer would see a 10.55% increase.

14

15

SERVICE RULES

16 **Q. Please describe UPPCO's proposed changes to the service rule tariffs.**

17 A. UPPCO is proposing minor additions and modifications to the service rule tariffs. On
18 sheet C-9.00, the language regarding special meter readings is being modified
19 slightly. UPPCO will continue to use the customer read to create the bill, but would
20 rather send an actual bill to the customer instead of communicating the information
21 verbally. UPPCO is also proposing to add a paragraph to the reconnection section
22 on C-11.00 to further clarify during and outside regular working hours and specify the
23 customers' obligations if more than one service call is required because the
24 customer was not present and/or prepared.

25

26

NATUREWISE

27 **Q. Please describe Schedule F10 of Exhibit A-6 (JMB-1).**

1 A. Schedule F10 shows the derivation of the proposed charge for the NatureWise
2 Program.

3

4 **Q. Please describe the NatureWise service offering.**

5 A. NatureWise is a voluntary program that is open to all customers who wish to
6 purchase renewable energy and support the development of renewable generation.
7 NatureWise was initiated in the spring of 2002, and at the end of 2010 UPPCO had
8 125 customers participating in the program, all of which are residential. Under this
9 program, customers sign up for the purchase of renewable power in 100 kWh blocks
10 at a current price of \$1.75 per block per month. This charge is in addition to the
11 charges of the standard rate schedule under which the customer receives service.
12 The additional NatureWise charge is intended to recover the incremental costs of the
13 renewable energy provided under the program.

14

15 **Q. Can you please provide a billing example of a residential customer that**
16 **participates in the current NatureWise program?**

17 A. Yes, I can. The example below illustrates the billing for a customer using 500 kWh a
18 month on the A-1 rate schedule and purchasing one 100 kWh block of NatureWise
19 service, excluding the PSCR factor.

20

A-1	
Customer Charge	\$10.00
Energy Charge (500 kWh * \$0.17411/kWh)	\$87.06
Total A-1	\$97.06
NatureWise (100 kWh * 1.75/block)	\$1.75
Total Monthly Bill (does not include sales tax)	\$98.81

21

1 **Q. Is UPPCO proposing to change the charge for NatureWise Service?**

2 A. Yes. UPPCO is proposing to increase the premium for a 100 kWh block to \$2.40, an
3 increase of \$0.65 from the current \$1.75 premium.

4

5 **Q. Why is UPPCO proposing to increase the NatureWise premium to \$2.40 instead
6 of the \$2.60 shown in the calculation on Exhibit A-6 (JMB-1), Schedule 10.**

7 A. The renewable resources that provide the renewable energy to meet the NatureWise
8 program are the same at both UPPCO and WPSC. The cause for the delta in the
9 premium between the WPSC rate and the UPPCO rate is primarily driven by the
10 calculation associated with the avoid cost of non-renewable power, or the Location
11 Marginal Price (LMP). The LMP variation can cause the avoided cost to move up
12 and down frequently, while the renewable costs have remained relatively static over
13 time. UPPCO is proposing to increase the premium to \$2.40 instead of the \$2.60 to
14 align with the NatureWise rate at WPSC. This alignment will create efficiencies in
15 program administration.

16

17 **Q. Please describe the derivation of the \$2.60/block premium proposed for the
18 NatureWise service.**

19 A. Schedule F10 of Exhibit A-6 (JMB-1) contains the derivation of the premium. The
20 charge is comprised of two types of costs, power supply related and non-power
21 supply related.

22

23 **Q. Please describe the power supply related costs for NatureWise service.**

24 A. Electric renewable generation is significantly more costly than non-renewable
25 generation. The top section of the exhibit calculates the cost of renewable
26 generation. The renewable generation under the NatureWise service is supplied by
27 approximately 50% wind power, 40% from landfill, 8% dairy digester and 2% solar.

1 The weighted average cost of renewable power from these sources for 2012 is
2 projected to be 7.683 cents per kWh. This cost was compared to UPPCO's
3 projected 2012 LMPs plus losses and capacity, which equate to 5.063 cents per
4 kWh. Thus, the incremental power supply cost for NatureWise is 2.621 cents/kWh
5 (7.683¢ - 5.063¢). Due to the current low market price of capacity, capacity costs
6 were not included in the derivation of the NatureWise premium.

7

8 **Q. Please describe the non-power supply related costs for NatureWise service.**

9 A. The non-power supply cost included in the NatureWise Program represents the
10 internal administration costs for signing up new customers and general oversight of
11 the NatureWise Program. These costs total \$62 for 2012. Based on a forecast of
12 180,000 kWh (1,800 - 100 kWh blocks), the cost per kWh of the non-power supply
13 costs is 0.020 cents per kWh.

14

15 **Q. Can you summarize the derivation of the proposed 2.60 cent per kWh or
16 \$2.60/block?**

17 A. Yes, I can. The 2.60 cent/kWh charge represents the sum of the power supply
18 related costs (2.621 cents per kWh), and the non-power supply costs (0.020 cents
19 per kWh).

20

21 **EXTENSION RULES**

22 **Q. What changes is UPPCO proposing to make to its current extension rules?**

23 A. UPPCO is proposing to make a few modifications to the extension rules including:

24 a. Winter Construction Charge

25 b. Adjustment to Actual

26 c. Customer Allowances

27 d. Return to Site Charge

1

2 **Q. What changes is UPPCO proposing to the winter construction charge?**

3 A. In Case No. U-16166, the Commission approved new extension rules patterned after
4 those in place for WPS Corp to promote standardization across jurisdictions. With
5 these rules, the winter construction season was set from December 1st to March 31st.
6 These dates are more reflective of the Wisconsin territory; therefore UPPCO would
7 like to change the winter construction season to November 1st to April 15th. These
8 dates are more reflective of the conditions in UPPCO's service territory.

9

10 **Q. Why does UPPCO want to increase the Adjustment to Actual amount?**

11 A. Currently, an adjustment is made for the customer requirements (refund or additional
12 payment) to reflect if actual investment is greater than \$20. UPPCO proposes to
13 increase this Adjustment to Actual amount to \$100.

14

15 **Q. Is UPPCO proposing to make any other changes to the extension rules?**

16 A. Yes it is. UPPCO is proposing to add language that allows the company to recover
17 costs from the customer for a return to site visit. This charge would be applied when
18 a customer tells UPPCO their site is ready for facilities to be installed, but when the
19 contractor arrives to install underground facilities the site is not ready. When this
20 situation occurs, the contractor then bills UPPCO for the costs. Currently, this cost is
21 not passed on to the customer, but is socialized among all rate payers. UPPCO
22 would like to apply the cost for a return to site visit directly to the customer requesting
23 the work.

24

25 **ELECTRIC EXTENSION ALLOWANCE**

26 **Q. Please describe Exhibit A-6 (JMB-1), Schedule F11.**

27 A. Schedule F11 is a determination of the appropriate 2012 electric distribution

1 extension allowances. The allowance for each rate group reflects the net distribution
2 plant cost per customer class. This methodology was approved in Case U-16166.

3
4 **Q. Could you please identify the electric extension allowances being proposed in**
5 **UPPCO’s 2012 rate case?**

6 A. Yes. The following table indicates the electric extension allowances that are
7 proposed in this rate case for implementation in 2012.

Rate Group	2012 Proposed
Residential	\$497
*C/I Energy Only	\$713
C/I Demand / kW	\$66

8
9 *C/I = Commercial/Industrial

10
11 **COMBINED RATE DESIGN**

12 **Q. Please describe Exhibit A-6 (JMB-1), Schedule F13.**

13 A. Order Point “N” of the Commission’s December 21, 2010 Order Approving
14 Settlement Agreement in Case No. U-16166 requires UPPCO to include in the
15 instant general rate case filing a proposal for rate consolidation of the Integrated and
16 Iron River systems. Throughout testimony each combined rate schedule is listed
17 and the impacts to customers are stated. Schedule F13 includes:

18 Page 1: Present and Proposed Revenues by Rate Schedule.

19
20 Page 2: Demonstrates the impacts combining the Iron River and Integrated
21 System would have on each existing rate schedule.

22
23 Page 3 – 22: Contains revenue calculations by rate schedule and billing
24 determinants for both the Integrated and Iron River Systems. The proposed
25 rates on Schedule F3 are designed to recover the UPPCO revenue
26 deficiency.

27
28 Page 23 – 43: Calculates typical monthly bills for customers served at

1 various monthly energy and/or demand levels. Each line shows a typical
2 monthly bill under proposed rates, a typical bill under present rates, the
3 amount of the proposed rate increase, and the percent increase.

4
5 Page 44 – 47: Rate realignment plan

6
7 Page 48 – 49: For completeness only, the Present and Proposed Revenues
8 by Rate Schedule assuming revenue neutrality.

9

10

SELF-IMPLEMENTED RATE DESIGN

11 **Q. Please provide an overview of the proposed self-implemented rate design.**

12 A. As authorized by MCL 460.6a(1), UPPCO intends to self-implement rates for service
13 rendered on and after January 1, 2012. The self-implemented increase is
14 \$7,061,647 for the Integrated Retail System and \$639,641 for the Iron River System.
15 The proposed rate design is set forth in Schedule F6 of Exhibit A-6 (JMB-1).

16

17 A proposed tariff sheet can be found in Schedule F5 of Exhibit A-6 (JMB-1).

18

19 **Q. How did UPPCO allocate the rate increase amongst the rate schedules?**

20 A. UPPCO's self-implemented rate increase was calculated in accordance with MCL
21 460.6a(1), which requires an equal percentage increase across all rate schedules,
22 excluding NatureWise. The Integrated Retail and Iron River Systems were treated
23 as one system for this calculation. Furthermore, neither the UPPCO COSS nor the
24 structural rate design changes proposed for final rates were considered in the
25 development and creation of the proposed self-implemented rate levels.

26

27 **Q. Does this complete your pre-filed direct testimony?**

28 A. Yes, it does.